(b) * * *

(L) State of Georgia: Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, 4244 International Parkway, Suite 120, Atlanta, Georgia 30354.

* * * * *

(Z) State of Mississippi: Hand Deliver or Courier: Mississippi Department of Environmental Quality, Office of Pollution Control, Air Division, 515 East Amite Street, Jackson, Mississippi 39201, Mailing Address: Mississippi Department of Environmental Quality, Office of Pollution Control, Air Division, P.O. Box 2261, Jackson, Mississippi 39225.

* * * * *

(II) State of North Carolina: North Carolina Department of Environment and Natural Resources, Division of Air Quality, 1641 Mail Service Center, Raleigh, North Carolina 27699–1641 or local agencies, Forsyth County Environmental Affairs, 201 North Chestnut Street, Winston-Salem, North Carolina 27101 or Forsyth County Air Quality Section, 537 North Spruce Street, Winston-Salem, North Carolina 27101; Mecklenburg County Land Use & Environmental Services Agency, Air Quality, 700 N. Tryon St., Suite 205, Charlotte, North Carolina 28202–2236; Western North Carolina Regional Air Quality Agency, 49 Mount Carmel Road, Asheville, North Carolina 28806.

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[FR Doc. 2012–9234 Filed 4–18–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044; FRL–9654–8]

RIN 2060–AP52 and 2060–AR31

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; correction.

SUMMARY: This document corrects certain preamble and regulatory text. This action corrects typographical errors, such as cross-reference errors and certain preamble text that is not consistent with the final regulatory text, which published in the **Federal Register** on Thursday, February 16, 2012 (77 FR 9304).

DATES: *Effective date:* April 19, 2012.

FOR FURTHER INFORMATION CONTACT: For the NESHAP action: Mr. William Maxwell, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5430; Fax number (919) 541–5450; email address: *maxwell.bill@epa.gov.* For the new source performance standard (NSPS) action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–4003; Fax number (919) 541–5450; email address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION: This document corrects certain preamble and regulatory text. It is proper to issue this final rule correction without notice and comment. Section 553 of the Administrative Procedure Act (APA), 5 U.S.C. 553(b)(B), provides that, when an agency for good cause finds that notice and public procedure are impracticable, unnecessary, or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. We have determined that there is good cause for making this action final without prior proposal and opportunity for comment because the changes to the rule are minor technical corrections, are noncontroversial, and do not substantively change the agency actions taken in the final rule. Notice and comment is unnecessary, because these changes do not affect the rights or obligations of outside parties, and do not alter the substantive requirements of the code of federal regulations (CFR), except to the extent that one regulatory provision included an inadvertent typographical error that EPA must amend to align with the plain text of the Clean Air Act (CAA). We find that this constitutes good cause under 5 U.S.C. 553(b)(B).The corrections can be categorized generally as follows: Correction of typographical errors (e.g., cross-reference errors) and correction of certain preamble text that does not conform to the final regulatory text. Below, we identify each technical correction to the preamble and regulatory text.

1. Table 5 on page 9368 is corrected to read as follows:

TABLE 5—ALTERNATE EMISSION LIMITATIONS FOR EXISTING COAL- AND OIL-FIRED EGUS

Subcategory/pollutant	Coal-fired EGUs	IGCC	Liquid oil, continental	Liquid oil, non-continental	Solid oil-derived
SO_2	2.0E–1 lb/MMBtu (1.5E0 lb/MWh).	NA	NA	NA	3.0E–1 lb/MMBtu (2.0E0 lb/MWh).
Total non-mercury metals.	5.0E–5 lb/MMBtu (5.0E–1 lb/GWh).	6.0E–5 lb/MMBtu (5.0E–1 lb/GWh).	8.0E–4 lb/MMBtu (8.0E–3 lb/MWh) [a].	6.0E–4 lb/MMBtu(7.0E–3 lb/MWh) [a].	4.0E–5 lb/MMBtu (6.0E–1 lb/GWh).
Antimony, Sb	8.0E–1 lb/TBtu (8.0E–3 lb/GWh).	1.4E0 lb/TBtu (2.0E–2 lb/GWh).	1.3E+1 lb/TBtu (2.0E–1 lb/GWh).	2.2E0 lb/TBtu (2.0E–2 lb/GWh).	8.0E–1 lb/TBtu (7.0E–3 lb/GWh).
Arsenic, As	1.1E0 lb/TBtu (2.0E–2 lb/GWh).	1.5E0 lb/TBtu (2.0E–2 lb/GWh).	2.8E0 lb/TBtu (3.0E–2 lb/GWh).	4.3E0 lb/TBtu (8.0E–2 lb/GWh).	3.0E–1 lb/TBtu (5.0E–3 lb/GWh).
Beryllium, Be	2.0E–1 lb/TBtu (2.0E–3 lb/GWh).	1.0E–1 lb/TBtu (1.0E–3 lb/GWh).	2.0E–1 lb/TBtu (2.0E–3 lb/GWh).	6.0E–1 lb/TBtu (3.0E–3 lb/GWh).	6.0E–2 lb/TBtu (5.0E–4 lb/GWh).
Cadmium, Cd	3.0E–1 lb/TBtu (3.0E–3 lb/GWh).	1.5E–1 lb/TBtu (2.0E–3 lb/GWh).	3.0E–1 lb/TBtu 2.0E–3 lb/GWh).	3.0E–1 lb/TBtu (3.0E–3 lb/GWh).	3.0E–1 lb/TBtu (4.0E–3 lb/GWh).
Chromium, Cr	2.8E0 lb/TBtu (3.0E–2 lb/GWh).	2.9E0 lb/TBtu (3.0E–2 lb/GWh).	5.5E0 lb/TBtu (6.0E–2 lb/GWh).	3.1E+1 lb/TBtu (3.0E–1 lb/GWh).	8.0E–1 lb/TBtu (2.0E–2 lb/GWh).
Cobalt, Co	8.0E–1 lb/TBtu (8.0E–3 lb/GWh).	1.2E0 lb/TBtu (2.0E–2 lb/GWh).	2.1E+1 lb/TBtu (3.0E–1 lb/GWh).	1.1E+2 lb/TBtu (1.4E0 lb/GWh).	1.1E0 lb/TBtu (2.0E–2 lb/GWh).

TABLE 5—ALTERNATE EMISSION LIMITATIONS FOR EXISTING COAL- AND OIL-FIRED EGUS—Continued

Subcategory/pollutant	Coal-fired EGUs	IGCC	Liquid oil, continental	Liquid oil, non-continental	Solid oil-derived
Lead, Pb	1.2E0 lb/TBtu (2.0E–2 lb/GWh).	1.9E+2 lb/TBtu (1.8E0 lb/GWh).	8.1E0 lb/TBtu (8.0E–2 lb/GWh).	4.9E0 lb/TBtu (8.0E–2 lb/GWh).	8.0E–1 lb/TBtu (2.0E–2 lb/GWh).
Manganese, Mn	4.0E0 lb/TBtu (5.0E–2 lb/GWh.	2.5E0 lb/TBtu (3.0E–2 lb/GWh).	2.2E+1 lb/TBtu (3.0E–1 lb/GWh).	2.0E+1 lb/TBtu (3.0E–1 lb/GWh).	2.3E0 lb/TBtu (4.0E–2 lb/GWh).
Mercury, Hg	NA	NA	2.0E–1 lb/TBtu (2.0E–3 lb/GWh).	4.0E–2 lb/TBtu (4.0E–4 lb/GWh).	NA.
Nickel, Ni	3.5E0 lb/TBtu (4.0E–2 lb/GWh).	6.5E0 lb/TBtu (7.0E–2 lb/GWh).	1.1E+2 lb/TBtu (1.1E0 lb/GWh).	4.7E+2 lb/TBtu (4.1E0 lb/GWh).	9.0E0 lb/TBtu (2.0E–1 lb/GWh).
Selenium, Se	5.0E0 lb/TBtu (6.0E–2 lb/GWh).	2.2E+1 lb/TBtu (3.0E–1 lb/GWh).	3.3E0 lb/TBtu (4.0E–2 lb/GWh).	9.8E0 lb/TBtu (2.0E–1 lb/GWh).	1.2E0 lb/TBtu (2.0E–2 lb/GWh).

NA = Not applicable.
[a] Includes Hg.

The output-format values for the antimony and beryllium emission limits for existing solid oil-derived fuel-fired units were incorrect as published in the preamble to the final rule (i.e., the incorrect "8.0E–3 lb/GWh" instead of the correct "7.0E–3 lb/GWh" for antimony and the incorrect "6.0E–4 lb/GWh" instead of the correct "5.0E–4 lb/GWh" for beryllium). In addition, the format of the input- and output-based lead emissions limits for existing IGCC EGUs was incorrect as published in the preamble to the final rule (i.e., the incorrect "1.9E+2 lb/MMBtu or 1.8E0 lb/MWh" instead of the correct "1.9E+2 lb/TBtu or 1.8E0 lb/GWh"). In each case, the correct values are indicated in the spreadsheets found in docket entry EPA–HQ–OAR–2009–0234–20132 and the published values were transcription errors. This same correction is made to the regulatory text later in this document.

2. On page 9401, column 1, first full paragraph, the fourth sentence is corrected to read as follows: "This subcategory applies only to oil-fired EGUs that act as peaking units, as they generally address reliability issues."

We are revising this sentence because the original sentence in the preamble to the final rule stated: "This subcategory applies only to oil-fired EGUs *that operate on oil alone* and act as peaking units, as they generally address reliability issues." (emphasis added). The italicized language is not consistent with the regulatory definition of "oil-fired EGU" or the definition of "limited-use liquid oil-fired subcategory" because it incorrectly indicates that the subcategory applies only to oil-fired EGUs that operate on oil alone. See 40 CFR 63.10042.

3. The definition of "Boiler operating day" in § 60.41Da Definitions, the date "February 29, 2005" is corrected to read "March 1, 2005" because there was no February 29 in 2005.

4. Section 60.49Da(a)(4)(i) is revised to correct the typographical error related to the incorrect cross reference to section 60.51a(d) which does not exist. The correct cross reference is to section 60.51Da(d).

5. Sections 63.9982(a)(1) and (a)(2) are revised to include the "§" symbol which was inadvertently left off of the references to section 63.10042 (i.e., "63.10042" vs. the correct "§ 63.10042".

6. Section 63.9982(d) is revised to correct the typographical error which left out the word "in" from the phrase "* * * change in process * * *"

7. Section 63.9985(a)(2) is revised to remove the words "or modification." We erroneously included this language in the final rule definition of a new source for purposes of the NESHAP. The language included in the final rule comes from the CAA section 111 statutory definition for "new source," instead of the CAA section 112 definition of "new source." CAA section 112 does not include "modified" sources in the definition of new sources, and, thus, the inclusion of such sources in the definition was an inadvertent drafting error.

8. Section 63.9991(c) is revised to remove the term "coal-fired" from the phrase "coal-fired EGU." This section expressly references Tables 1 and 2 of this subpart and those tables include alterative sulfur dioxide (SO_2) limits for all EGUs meeting the requirements of section 63.9991(c), not just coal-fired EGUs. Thus, the provision as written in the final rule was incorrectly limited to coal-fired EGUs.

9. Section 63.10000(c)(1) is revised to include integrated gasification combined cycle (IGCC) EGUs among the subcategories listed. Section 63.10000(c) addresses initial performance testing. IGCC EGUs are included in the requirements of section 63.10000(c)(1)(i) (which deals with initial performance testing for purposes of determining low emitting EGU (LEE) status) and, thus, the omission of IGCC EGUs from the introductory language in section 63.10000(c)(1) was an inadvertent error.

10. Section 63.10000(c)(1)(i)(B) is revised to correct a typographical error ("* * * solid oil-derived fuel-fired * * *" rather than the incorrect "* * * solid oil-fired fuel-fired * * *").

11. Section 63.10000(c)(2)(iv) is revised to correct a typographical error and include "you" in the phrase "* * * but you must * * *"

12. Section 63.10000(d)(5)(i) is revised to correct the typographical error of including the incorrect term "CEMS" rather than the correct term "CMS." The text of sections 63.10000(d)(2)(i), (3), and (4) all refer to the broader "CMS" (which includes both continuous parameter monitoring system (CPMS) and continuous emission monitoring system (CEMS)). Thus, use of the narrower CEMS in section 63.10000(d)(5)(i) was an inadvertent error. Further, the term "CPMS" in the last sentence of the section is corrected to read "PM CPMS" consistent with section 63.10010(h), which section is referenced in section 63.10000(d)(5)(i) and specifically addresses PM CPMS.

13. Section 63.10000(d)(5)(iv) is revised to use language consistent with section 63.8(d) (changing "ongoing data quality assurance procedures" to "quality control program"), as section 63.8 is cited in this section. The title of section 63.8(d) is "quality control program" and the phrase "ongoing data quality assurance procedures" does not appear in that provision.

14. Section 63.10000(f) is revised to correct a typographical error by replacing "distributions system" with the correct "distribution system."

15. Section 63.10005(b)(2) is revised to correct a typographical error by changing "* * * valid data CMS data * * *" to "valid CMS data".

16. Section 63.10005(d)(1) is revised to correct a typographical error (the correct "* * * Table 1 or 2 to this * * *" rather than the incorrect "* * * Table 1 or 2 of this * * *" in two places).

17. Section 63.10005(d)(4)(ii) is revised to correct the typographical error associated with the use of "corresponding" rather than the correct word "corresponds."

18. Sections 63.10005(h)(3)(iii)(C)(*1*) and (*2*) are revised to correct the typographical errors associated with the conversion factors from million British thermal units per hour (MMBtu/hr) to trillion Btu/hr (TBtu/hr) (i.e., the correct 10^{-6} rather than the incorrect 10^{6}) and from megawatts (MW) to gigawatts (GW) (i.e., the correct 10^{-3} rather than the incorrect 10^{3}). The exponents as published are technically incorrect and the conversions would not work as published.

19. Section 63.10006(a) is revised to correct a typographical error. Specifically, we inadvertently omitted the word "fired" from the phrase "* * * solid oil-derived fuel- and * * *" The phrase should read "* * * solid oil-derived fuel-fired and * * *"

20. Section 63.10007(c) is revised to correct the typographical error associated with the incorrect cross reference to the non-existent section 63.10011(b)(5). The correct cross reference is to section 63.10011(b).

21. Section 63.10009(g) is revised to correct the typographical error related to the incorrect cross reference to sections 63.10009(f)(1) through (3). Section 63.10009(g) deals with determining weighted average emission rates, but section 63.10009(f) deals with demonstrating eligibility for an emissions averaging group and is, thus, an incorrect cross reference. The correct cross reference is to sections 63.10009(g)(1) through (2), which sections provide specific direction on the manner in which sources establish weighted average emission rates.

22. Section 63.10009(j)(2)(i)(A) is revised to correct the typographical error related to the incorrect cross reference to section 63.10009(h)(1), which does not exist. The correct cross reference is to section 63.10009(j)(1).

23. Sections 63.10010(a)(6)(iii) and (iv) are revised to correct the typographical errors related to the incorrect cross references to sections 63.10010(a)(5)(iii)(B) and (a)(5)(iii)(C), which do not exist. The correct cross references are to sections 63.10010(a)(6)(ii) and (iii), respectively.

24. Sections 63.10010(g), 63.10011(c)(1), 63.10021(b), and 63.10022(a)(1) are revised to correct the inadvertent omission of the alternate 90-day averaging period. The provisions as included in the final rule only referred to the 30-day averaging periods that are generally utilized for determining compliance with the final standards; however, as indicated in section 63.10009(a)(2), sources are also authorized to use the alternate 90-day averaging period for certain standards when emissions averaging is employed at a facility.

25. Section 63.10020(d) is revised to correct a typographical error by replacing "of" with "from" in the phrase "* * * deviation from the * * *"

26. Section 63.10030(e)(7)(i) is revised to correct the typographical error related to the incorrect cross reference to section 63.10006(i). Section 63.10006(i) addresses the tune-up requirement, but section 63.10030(e)(7)(i) concerns LEE requirements, not tune-up requirements. The correct cross reference is to section 63.10006(b), which addresses the reduced performance (i.e., stack) testing for LEE, which allows a source to test every 3 years as discussed in section 63.10030(e)(7)(i).

27. Section 63.10031(c)(4) is revised to correct an incorrect statement. The final rule does not require annual inspections; thus, the "annual" has been replaced with "every 36 (or 48) months" to be consistent with other rule text.

28. The definitions of "Non-mercury (Hg) HAP metals" and "Oil" in section 63.10042 are revised to correct the typographical error that did not separate the two definitions in the published rule.

29. Table 2 to Subpart UUUUU of Part 63 is revised to correct the typographical errors related to the lack of a superscript for footnotes ("2") denoting "gross electric output" for filterable particulate matter emissions from "2. Coal-fired unit low rank virgin coal," "3. IGCC," "4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)," "Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)," and "6. Solid oil-derived fuel-fired unit."

In addition, the format of the input- and output-based lead emissions limits for "3. IGCC unit" was incorrect as published (i.e., the incorrect "1.9E+2 lb/MMBtu or 1.8E0 lb/MWh" instead of the correct "1.9E+2 lb/TBtu or 1.8E0 lb/GWh"). Further, the output-format values for the antimony and beryllium emission limits for "6. Solid oil-derived fuel-fired unit" were incorrect as published (i.e., the incorrect "8.0E–3 lb/GWh" instead of the correct "7.0E–3 lb/GWh" for antimony and the incorrect "6.0E–4 lb/GWh" instead of the correct "5.0E–4 lb/GWh" for beryllium). In each case, the correct values are indicated in the spreadsheets found in docket entry EPA–HQ–OAR–2009–0234–20132 and the published values are transcription errors.

30. For the reasons described in Paragraph 24 above, Table 7 to Subpart UUUUU of Part 63 is revised to address the inadvertent omission of the alternate 90-day averaging period that is available.

31. For the reasons described in Paragraph 24 above, Paragraphs 6.2.1.4 and 6.2.2.3 to Appendix A to Subpart UUUUU of Part 63 are revised to address the inadvertent omission of the alternate 90-day averaging period that is available.

32. Paragraph 7.2.4 to Appendix A to Subpart UUUUU of Part 63 is revised to correct the typographical error related to the incorrect cross reference to paragraphs 7.1.10.1 through 7.1.10.7; these paragraphs do not exist, however. The correct cross reference is paragraphs 7.1.9.1 through 7.1.9.7.

33. Paragraph 7.2.5.3.4 to Appendix A to Subpart UUUUU of Part 63 is revised to correct the typographical error related to the incorrect cross reference to paragraph 7.1.90.1; this paragraph does not exist, however. The correct cross reference is paragraph 7.1.9.1.

Statutory and Executive Order Reviews

Under Executive Order (EO) 12866, Regulatory Planning and Review (58 FR 51735, October 4, 1993), this action is not a "significant regulatory action" and is therefore not subject to review by the Office of Management and Budget (OMB). This action is not a "major rule" as defined by 5 U.S.C. 804(2). The technical corrections do not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

Because EPA has made a "good cause" finding that this action is not subject to notice and comment requirements under the APA or any other statute, it is not subject to the regulatory flexibility provisions of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), or to sections 202 and 205 of the Unfunded Mandates Reform Act of 1995 (UMRA) (Pub. L. 104–4). In addition, this action does not significantly or uniquely affect small governments or impose a significant intergovernmental mandate, as described in sections 203 and 204 of the UMRA.

The corrections do not have substantial direct effects on the states, or on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132, Federalism (64 FR 43255, August 10, 1999).

This action also does not significantly or uniquely affect the communities of tribal governments, as specified by EO 13175, Consultation and Coordination with Indian Tribal Governments (65 FR 67249, November 9, 2000). The technical corrections also are not subject to EO 13045, Protection of Children from Environmental Health and Safety Risks (62 FR 19885, April 23, 1997) because this action is not economically significant.

The corrections are not subject to EO 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use (66 FR 28355, May 22, 2001) because this action is not a significant regulatory action under EO 12866.

The corrections do not involve changes to the technical standards related to test methods or monitoring methods; thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272) do not apply.

The corrections also do not involve special consideration of environmental justice-related issues as required by EO 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (59 FR 7629, February 16, 1994).

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 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 U.S. The EPA submitted a report containing the final action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. This action is not a "major rule" as defined by 5 U.S.C. 804(2). The final rule will be effective on April 16, 2012.

The EPA's compliance with the above statutes and EOs for the underlying rule is discussed in the February 16, 2012, **Federal Register** document containing "National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units."

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, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: March 27, 2012.

Lisa P. Jackson,

Administrator.

Accordingly, title 40, chapter I, of the Code of the Federal Regulations is amended by making the following correcting amendments:

PART 60—[AMENDED]

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

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

■ 2. In § 60.41Da, revise the definition of "Boiler operating day" to read as follows:

§ 60.41Da Definitions.

* * * * *

Boiler operating day for units constructed, reconstructed, or modified before March 1, 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.

* * * * *

■ 3. Revise § 60.49Da(a)(4)(i) to read as follows:

§ 60.49Da Emission monitoring.

(a) * * *

(4) * * *

(i) The affected facility combusts only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.51Da(d).

* * * * *

PART 63—[AMENDED]

■ 4. The authority citation for 40 CFR Part 63 continues to read as follows:

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

■ 5. Revise § 63.9982(a)(1), (a)(2), and (d) to read as follows:

§ 60.9982 What is the affected source of this subpart?

(a) * * *

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in § 63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in § 63.10042.

* * * * *

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change in process (e.g., fuel or utilization) is considered to be an existing source under this subpart.

* * * * *

■ 6. Revise § 63.9985(a)(2) to read as follows:

§ 63.9985 What is a new EGU?

(a) * * *

(2) An EGU that commenced reconstruction after May 3, 2011.

* * * * *

■ 7. In § 63.9991, revise paragraph(c) introductory text to read as follows:

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

* * * * *

(c) You may use the alternate SO_2 limit in Tables 1 and 2 to this subpart only if your EGU:

* * * * *

■ 8. In § 63.10000, revise paragraphs(c)(1) introductory text, (c)(1)(i)(B), (c)(2)(iv), (d)(5)(i), (d)(5)(iv) and (f) to read as follows:

§ 63.10000 What are my general requirements for complying with this subpart?

* * * * *

(c)(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) * * *

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.

* * * * *

(2) * * *

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in § 63.10042, then you are not subject to the emission limits in Tables 1 and 2, but you must comply with the performance tune-up work practice requirements in Table 3.

* * * * *

(d) * * *

(5) * * *

(i) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See § 63.10010(a) for further details. For PM CPMS installations, follow the procedures in § 63.10010(h).

* * * * *

(iv) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of § 63.8(d).

* * * * *

(f) You are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (e.g., 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distribution system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless you are a solid waste incineration unit subject to standards under CAA section 129 (e.g., 40 CFR Part 60, Subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or Subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

* * * * *

■ 9. Revise § 63.10005(b)(2), (d)(1), (d)(4)(ii), and (h)(3)(iii)(C)(*1*) and (*2*) to read as follows:

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

* * * * *

(b) * * *

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid CMS data recorded in the 30 boiler operating days immediately preceding that date;

* * * * *

(d) * * *

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO_2, HCl, or HF emissions limit in Table 1 or 2 to this subpart through use of an SO_2, HCl, or HF CEMS installed and operated in accordance with Part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 to this subpart through use of a PM CEMS installed, certified, and operated in accordance with § 63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see § 63.10007(e)), meets the applicable SO_2, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19–19 of Method 19 in appendix A–7 to Part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (**Note:** For this calculation, the term E_{hj} in Equation 19–19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

* * * * *

(4) * * *

(i) * * *

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.

* * * * *

(h) * * *

(3) * * *

(iii) * * *

(C) * * *

(*1*) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^{-6} to convert it to TBtu/hr; or

(*2*) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^{-3} to convert it to GW; or

* * * * *

■ 10. Revise § 63.10006(a) to read as follows:

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and § 63.10007 at least every year.

* * * * *

■ 11. Revise § 63.10007(c) to read as follows:

§ 63.10007 What methods and other procedures must I use for the performance tests?

* * * * *

(c) If you choose to comply with the filterable PM emission limit and demonstrate continuous performance using a PM CPMS for an applicable emission limit as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b) and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

* * * * *

■ 12. In § 63.10009, revise paragraphs (g) introductory text and (j)(2)(i)(A) to read as follows:

§ 63.10009 May I use emissions averaging to comply with this subpart?

* * * * *

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 day rolling average (90 day rolling average for Hg) basis according to paragraphs (g)(1) through (2) of this section. The first averaging period begins on 30 (or 90 for Hg) days after February 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

* * * * *

(j) * * *

(2) * * *

(i) * * *

(A) Whether the content of the plan includes all of the information specified in paragraph (j)(1) of this section; and

* * * * *

■ 13. In § 63.10010, revise paragraphs (a)(6)(iii), (a)(6)(iv) and (g) to read as follows:

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) * * *

(6) * * *

(iii) Sum the products determined under paragraph (a)(6)(ii) of this section; and

(iv) Divide the result obtained in paragraph (a)(6)(iii) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

* * * * *

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

* * * * *

■ 14. Revise § 63.10011(c)(1) to read as follows:

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

* * * * *

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (e.g., Hg or HCl) directly, the first 30-boiler operating day (or, if alternate emissions averaging is used for Hg, the 90-boiler operating day) rolling average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

* * * * *

■ 15. Revise § 63.10020(d) to read as follows:

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

* * * * *

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation from the monitoring requirements.

* * * * *

■ 16. Revise § 63.10021(b) to read as follows:

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

* * * * *

(b) Except as otherwise provided in § 63.10020(c), if you use a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \quad (Eq.\ 8)$$

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

* * * * *

■ 17. Revise § 63.10022(a)(1) to read as follows:

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) * * *

(1) For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);

* * * * *

■ 18. Revise § 63.10030(e)(7)(i) to read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

(7) * * *

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10006(b), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

* * * * *

■ 19. Revise § 63.10031(c)(4) to read as follows:

§ 63.10031 What reports must I submit and when?

* * * * *

(c) * * *

(4) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to § 63.10021(e). Include the date of the most recent burner inspection if it was not done every 36 (or 48) months and was delayed until the next scheduled unit shutdown.

* * * * *

■ 20. In § 63.10042, revise the definition "Non-mercury (Hg) HAP metals" and add the definition "Oil" to read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se).

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (e.g., petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

* * * * *

■ 22. Revise table 2 and table 7 to Subpart UUUUU of Part 63 to read as follows:

Tables to Subpart UUUUU of Part 63

* * * * *

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh ..	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh. [2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Cadmium (Cd)	1.5E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E–2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh. [2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E–2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½; the standard.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per Run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh. [2]	Collect a minimum of 1 dscm per run.
	OR Total HAP metals	OR 6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be)	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Mercury (Hg)	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½; the standard.
	b. Hydrogen chloride (HCl)	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit ...	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh. [2]	Collect a minimum of 1 dscm per run.
	OR Total non-Hg HAP metals	OR 4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals	OR Collect a minimum of 3 dscm per run.	
	Antimony (Sb)	8.0E–1 lb/TBtu or 7.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–2 lb/TBtu or 5.0E–4 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 4.0E–3 lb/GWh.	
	Chromium (Cr)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E–1 lb/GWh.	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
	Selenium (Se)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	3.0E–1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or Sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.
[2] Gross electric output.
[3] Incorporated by reference, see § 63.14.
[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

* * * * *

TABLE 7 TO SUBPART UUUUU OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

[As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following]

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30-boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the arithmetic 30-boiler operating day rolling average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring for liquid oil-fired units for HCl and HF emission limit monitoring.	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired units to measure compliance with one or more applicable emissions limit in Table 1 or 2.	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.	Operating in accordance with Table 3.

* * * * *

■ 23. In Appendix A to Subpart UUUUU of Part 63, revise paragraphs 6.2.1.4, 6.2.2.3, 7.2.4, 7.2.5.3.4, to read as follows:

Appendix A to Subpart UUUUU—Hg Monitoring Provisions

* * * * *

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis, except as otherwise provided in § 63.10009(a)(2). Use Equation 19–19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term E_{hj} in Equation 19–19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

* * * * *

6.2.2.3 The applicable electrical output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30-boiler operating day rolling average basis, except as otherwise provided in § 63.10009(a)(2). Use Equation A–5 of this section to calculate the Hg emission rate for each averaging period.

$$\overline{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \qquad \text{(Equation A-5)}$$

Where:

$\bar{E}_o$ = Hg emission rate for the averaging period (lb/GWh).

E_{cho} = Electrical output-based hourly Hg emission rate for unit or stack operating hour "h" in the averaging period, from Equation A–4 of this section (lb/GWh).

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters.

(*Note:* Do *not* include non-operating hours with zero emission rates in the average).

* * * * *

7.2.4 *Certification, Recertification, and Quality-Assurance Test Reporting.* Except for daily QA tests of the required monitoring systems (i.e., calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.9.1 through 7.1.9.7 of this section (except for test results previously submitted, e.g., under the ARP) shall be submitted electronically, using the ECMPS Client Tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

* * * * *

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.9.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

* * * * *

[FR Doc. 2012–8703 Filed 4–18–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 372

[EPA–HQ–OEI–2011–0196; FRL–9660–9]

RIN 2025–AA31

Toxics Release Inventory (TRI) Reporting for Facilities Located in Indian Country and Clarification of Additional Opportunities Available to Tribal Governments Under the TRI Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is announcing new opportunities for tribal participation and engagement in the TRI Program. Under this final rule, TRI reporting facilities located in Indian country are required to report to the appropriate tribal government of their relevant area instead of the State. This rule also improves and clarifies certain opportunities allowing tribal governments to participate more fully in the TRI Program. Further, because tribal governmental structures may vary, EPA is updating its terminology to refer to the principal elected official of the Tribe as the "Tribal Chairperson or equivalent elected official." EPA is also amending its definition of "State" for purposes of 40 CFR part 372 to no longer include Indian country, so as to avoid any confusing overlap in terminology for facilities located in Indian country. With regard to the procedures for EPA to modify the list of covered chemicals and TRI reporting facilities, today's rule clarifies the opportunities available to tribal governments. In particular, EPA is including within the relevant provision an opportunity for the Tribal Chairperson or equivalent elected official to request that EPA apply the TRI reporting requirements to a specific facility located within the Tribe's Indian country. Secondly, EPA is clarifying in this rule that the Tribal Chairperson or equivalent elected official may petition EPA to add or delete a particular chemical respectively to or from the list of chemicals covered by TRI. In finalizing the actions described, EPA is helping to increase awareness of toxic releases within tribal communities, thereby increasing the understanding of potential human health and ecological impacts from these hazardous chemicals.

DATES: This final rule is effective April 19, 2012. The requirement of facilities located in Indian country to report to tribal governments is applicable beginning with TRI reporting year 2012 (TRI reports due by July 1, 2013).

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OEI–2011–0196. 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 OEI Docket, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1752.

FOR FURTHER INFORMATION CONTACT: Louise Camalier, Environmental Analysis Division, Office of Environmental Information (2842T), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 566–0503; fax number: (202) 566–0677; email address: *Camalier.louise@epa.gov,* for specific information on this notice. For general information on EPCRA Section 313, contact the Superfund, TRI, EPCRA, RMP & Oil Information Center toll free at (800) 424–9346, (703) 412–9810 in the Washington, DC metropolitan area, toll free TDD at (800) 553–7672, or visit the Web site at *http://www.epa.gov/superfund/contacts/infocenter.*

SUPPLEMENTARY INFORMATION:

I. General Information

Does this action apply to me?

You may be affected by this action if you own or operate a facility located in Indian country (see 40 CFR 372.3 for a definition of Indian country) with a toxic chemical(s) known by the owner or operator to be manufactured (including imported), processed, or otherwise used in excess of an applicable threshold quantity, as referenced in 40 CFR 372.25, 372.27, or 372.28, at its covered facility described in § 372.22. Potentially affected categories and entities may include, but are not limited to:

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0037; FRL–9636–2]

RIN 2060–AN33

National Emission Standards for Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is promulgating National Emission Standards for Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production. The final rules establish emission standards that apply at all times, including periods of startup, shutdown and malfunction, for hazardous air pollutants from polyvinyl chloride and copolymers production located at major and area sources. The final rules include requirements to demonstrate initial and continuous compliance with the emission standards, including monitoring provisions and recordkeeping and reporting requirements.

DATES: The final rules are effective on April 17, 2012. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of April 17, 2012.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2002–0037. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility 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 EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Jodi Howard, Sector Policies and Programs Division (E143–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–4607; Fax number: (919) 541–0246; email address: *howard.jodi@epa.gov.*

SUPPLEMENTARY INFORMATION:

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

CAA Clean Air Act
CDD/CDF chlorinated dibenzo-dioxins and furans
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS continuous emission monitoring system
CPMS continuous parameter monitoring system
DCS distributed control system
dscm dry standard cubic meter
EDC ethylene dichloride
ERT Electronic Reporting Tool
GACT generally available control technologies or management practices
HMW high molecular weight
HAP hazardous air pollutants
HCl hydrogen chloride
HON Hazardous Organic NESHAP
ICR information collection request
LAER lowest achievable emission rate
LDAR leak detection and repair
LMW low molecular weight
LOQ limit of quantitation
MACT maximum achievable control technology
MDL method detection levels
MON Miscellaneous Organic Chemical Manufacturing NESHAP
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
ng/dscm nanograms per dry standard cubic meter
NO_X nitrogen oxide
NTTAA National Technology Transfer and Advancement Act
OMB Office of Management and Budget
POD point of determination
POG point of generation
ppbv parts per billion by volume
ppbw parts per billion by weight
ppm parts per million
ppmv parts per million by volume
ppmw parts per million by weight
PQL practical quantitation limit
PRD pressure relief device
psia pounds per square inch absolute
PVC polyvinyl chloride and copolymers
PVCPU PVC production process unit
RCRA Resource Conservation and Recovery Act
RDL representative method detection level
RFA Regulatory Flexibility Act
RL reporting limit
SBREFA Small Business Regulatory Enforcement Fairness Act
SO_2 sulfur dioxide
TCEQ Texas Commission on Environmental Quality
TEQ toxic equivalent
THC total hydrocarbon
tpy tons per year
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
UPL upper predictive limit
VACO vinyl acetate copolymer
VCM vinyl chloride monomer
VCS voluntary consensus standards
VOC volatile organic compound
WWW World Wide Web

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

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I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. General Information

A. Does this action apply to me?

The final rules establish national emission standards for hazardous air pollutants (NESHAP) for polyvinyl chloride and copolymer (PVC) production. The regulated categories and entities potentially affected by these standards include the following:

Category	NAICS [a] Code	Examples of potentially regulated entities
Polyvinyl chloride resins manufacturing ...	325211	Facilities that polymerize vinyl chloride monomer to produce polyvinyl chloride and/or copolymers products.

[a] 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 affected by this action. To determine whether your facility, company, business, organization, etc., is affected by this action, you should examine the applicability criteria in 40 CFR part 63, subpart HHHHHHH (National Emission Standards for Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production) and in 40 CFR part 63, subpart DDDDDD (National Emission Standards for Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production Area Sources).

A polyvinyl chloride and copolymer production facility is not subject to either subpart if it is a research and development facility, as defined in section 112(c)(7) of the Clean Air Act (CAA). If you have any questions regarding the applicability of this final 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 action will also be available on the World Wide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the 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 CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by June 18, 2012. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment (including any public hearing) can be raised during judicial review. This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to 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 this rule." Any person seeking to make such a demonstration to the EPA should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to the contact 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 for the Air and Radiation Law Office (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

II. Background Information for This Final Rule

A. What is the statutory authority for the final PVC rules?

Section 112(d) of the CAA requires the EPA to establish NESHAP for source categories and subcategories of both major and area sources of hazardous air pollutants (HAP) that are listed for regulation under CAA section 112(c). A major source emits or has the potential to emit 10 tons per year (tpy) or more of any single HAP or 25 tpy or more of any combination of HAP. An area source is a HAP-emitting stationary source that is not a major source.

Section 112(d) of the CAA requires the EPA to set emissions standards for HAP emitted by major stationary sources, based on performance of the maximum achievable control technology (MACT). The MACT standards for existing sources must be at least as stringent as the average emissions limitation achieved by the best-performing 12 percent of existing sources (for which the Administrator has emissions information) or the best-performing five sources for source categories or subcategories with fewer than 30 sources (CAA section 112(d)(3)(A) and (B)). This minimum level of stringency is called the MACT floor. For new sources, MACT standards must be at least as stringent as the control level achieved in practice by the best-controlled similar source (CAA section 112(d)(3)). The EPA also must consider more stringent "beyond-the-floor" control options. When considering beyond-the-floor options, the EPA must consider not only the maximum degree of reduction in emissions of HAP, but must take into account costs, energy and non-air

quality health and environmental impacts when doing so.

Under CAA section 112(d)(5), the EPA can promulgate standards or requirements for area sources "which provide for the use of generally available control technologies or management practices [GACT] by such sources to reduce emissions of hazardous air pollutants." Additional information on generally available control technology (GACT) is found in the Senate report on the legislation (Senate Report Number 101–228, December 20, 1989), which describes GACT as:

> * * * methods, practices and techniques which are commercially available and appropriate for application by the sources in the category considering economic impacts and the technical capabilities of the firms to operate and maintain the emissions control systems.

Consistent with the legislative history, we can consider costs and economic impacts in determining GACT.

Determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. We also consider the standards applicable to major sources in the analogous source category to determine if the control technologies and management practices are transferable and generally available to area sources. In appropriate circumstances, we may also consider technologies and practices at area and major sources in similar categories to determine whether such technologies and practices could be considered generally available for the area source categories at issue. Finally, as noted above, in determining GACT for a particular area source category, we consider the costs and economic impacts of available control technologies and management practices on that category.

Under CAA section 112(d)(6), we are required to "review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years."

B. 2004 Vacatur and EPA's Response

On July 10, 2002, the EPA promulgated NESHAP for new and existing PVC production facilities that are located at major sources in 40 CFR part 63, subpart J (67 FR 45886, July 10, 2002) (referred to as the "part 63 NESHAP"). In that rulemaking, the EPA determined that compliance with the existing Vinyl Chloride NESHAP (40 CFR part 61, subpart F) (referred to as the "part 61 NESHAP") reflected the application of MACT; thus, satisfying CAA section 112(d), with the exception of adding requirements for equipment leaks at new sources. In the part 63 NESHAP, the EPA regulated vinyl chloride emissions as a surrogate for all HAP emitted from PVC production. For equipment leaks, the part 63 NESHAP required that new sources comply with 40 CFR part 63, subpart UU, National Emission Standards for Equipment Leaks—Control Level 2 Standards.

In *Mossville Environmental Action Now* v. *EPA*, 370 F.3d 1232 (DC Cir. 2004), the petitioners argued that the EPA failed to set emission standards for all HAP emitted by PVC plants. The EPA had set emission standards for vinyl chloride as a surrogate for the remaining HAP because it was the predominant HAP used and emitted at PVC plants. The Court ruled that the EPA did not adequately explain the basis for its decision to use vinyl chloride as a surrogate for other HAP. The Court "vacated and remanded [the rule in its entirety] to the agency for it to reconsider or properly explain its methodology for regulating [HAP] emitted in PVC production other than vinyl chloride by use of a surrogate." 370 F.3d at 1243. This rule promulgates NESHAP for PVC production at major sources in response to the remand and in accordance with section 112 of the CAA.

On January 23, 2007 (72 FR 2930), the EPA promulgated NESHAP for new and existing PVC production area sources in 40 CFR part 63, subpart DDDDDD. Subpart DDDDDD was based on GACT and required area sources to meet the requirements in the existing part 61 NESHAP. The part 61 NESHAP requirements address only vinyl chloride emissions. In this rulemaking, we are fulfilling our obligation under CAA section 112(d)(6) to review and revise, as necessary, the PVC production area source standards. We coordinated our CAA 112(d)(6) review of the area source standards with the development of major source MACT standards in response to the Court remand.

III. Summary of Significant Changes Since Proposal

The EPA received over 39 public comment letters on the proposed rulemaking. Furthermore, we conducted two public hearings to allow the public to comment on the proposed rulemaking. After consideration of public comments and new data received, the EPA is making several changes to the standards. Following are the major changes to the standards since the proposal. The rationale for these and other significant changes can be found in section V of this preamble or in the *National Emission Standards for Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production: Summary of Public Comments and Responses*, in the PVC docket (EPA–HQ–OAR–2002–0037).

A. Applicability

The definition of affected source was changed to clarify the requirements for existing and new affected sources. In the proposed rule, an affected source was defined as each individual PVC production process unit (PVCPU) and a new affected source was a PVCPU for which construction commenced on or after May 20, 2011, at a major or area source. A PVCPU was defined to include all equipment connected by shared piping, including equipment typically shared by multiple PVCPU, such as heat exchangers and wastewater treatment systems.

In the final rule, the existing affected source is the facility-wide collection of all PVCPU, storage vessels, surge control vessels, heat exchange systems, wastewater, and process wastewater treatment systems that are associated with producing PVC. A new affected source is defined as follows:

- All PVCPU, storage vessels, surge control vessels, heat exchange systems, wastewater and process wastewater treatment systems that are associated with producing PVC and are constructed at a Greenfield facility after May 20, 2011; or that are located at an existing facility that did not previously produce PVC prior to the rule proposal but has undergone process changes to start producing PVC.
- A reconstructed affected source.

As an example, if an existing PVC plant adds a new PVCPU, the new PVCPU and the associated emission control devices and wastewater treatment processes would be subject to the existing source NESHAP limits, unless it qualifies as a reconstructed source. A newly constructed PVCPU would be subject to the new source requirements in the final rules only if it was constructed at a Greenfield site or at a site that had not previously produced PVC prior to the date of proposal of this rule (May 20, 2011) or if it qualifies as a reconstructed source.

B. Subcategories

At proposal, we did not subcategorize process vents. In the final rule, we have established two subcategories for process vents: PVC-only and PVC-combined. PVC-only process vents comprise process vent streams that

originate solely from a PVCPU. PVC-combined process vents comprise process vent streams that originate from a PVCPU and that are combined or are co-controlled with process vent streams that originate from other source categories such as ethylene dichloride (EDC) or vinyl chloride monomer (VCM) production processes. The change to subcategories was based on our review of comments, further review of the originally submitted test data, and our review of additional data submitted by industry after proposal. We determined that there are significant differences between the emission profiles of process vents that originate solely from a PVCPU and the emission profiles of process vents that originate from a PVCPU and are combined with process vents from other source categories prior to control. Further discussion of the differences between PVC-only and PVC-combined process vent streams is provided in section V.D of this preamble, and data showing the differences is provided in the memorandum, *Revised Maximum Achievable Control Technology (MACT) Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category, which is available in the docket.*

A facility subject to the PVC-combined limits that no longer combines vent streams from other source categories, or a facility that is subject to the PVC-only limits that subsequently combines vent streams from other source categories, is subject to the process change requirements in 40 CFR 63.11896 of the final rule. Routine and maintenance shutdowns that cause temporary cessation of the vent stream flow from other source categories are not subject to the process change requirements.

At proposal, we subcategorized stripped resins into three subcategories: (1) Bulk resin, (2) dispersion resin and (3) all other resin. For the final rule, we subcategorized stripped resins into five subcategories: (1) Suspension resin, (2) dispersion resin, (3) suspension blending resin, (4) bulk resin and (5) copolymer resin. The change to subcategories was made based on our review of comments and additional data submitted by the industry (see section V.D of this preamble for more discussion of our response to these and other public comments) after proposal. We determined that there are significant differences in the concentrations of vinyl chloride and organic HAP that remain in the various types of resin following stripping due to differing process equipment and raw materials that are used to produce the varying types of resins, such that further subcategorization of stripped resin was warranted.

C. Emission Standards

In the final rule, we revised the emission limits based on additional data received and the additional subcategories for process vents and stripped resins. The emission limit changes are discussed in section V.E.2 of this preamble and documented in the technical memorandum, *Revised Maximum Achievable Control Technology (MACT) Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* which is available in the docket. We also made revisions to the requirements for process wastewater, heat exchange systems, equipment leaks and other emission sources as discussed below.

We considered all the data regarding the PVC source category available to the agency in establishing the emission limits presented in Tables 1 through 8 below for process vents, stripped resins, and process wastewater. In reviewing those data, we found that the HAP emitted from the PVC source category are organic HAP (including vinyl chloride and chlorinated dibenzo-dioxins and furans (CDD/CDF)) and hydrogen chloride (HCl). We did not identify in the data any inorganic HAP, metal HAP, or any acid gases other than HCl, which is also a surrogate for chlorine gas. In setting limits for all HAP emitted at PVC major sources, we established total hydrocarbons (THC) limits as a surrogate for organic HAP from process vents, along with limits for HCl as a surrogate for all acid gas HAP and chlorine gas, vinyl chloride, and CDD/CDF. Although vinyl chloride and CDD/CDF are organic HAP, we established separate limits for these pollutants. Vinyl chloride is the primary ingredient in PVC production and is present at all emission points. Vinyl chloride, which is also an urban HAP, is already regulated at PVC facilities under the part 61 NESHAP. However, we are not setting vinyl chloride limits as a surrogate for other HAP. The CDD/CDF emissions are generated from combustion control of organic HAP from process vents (as is HCl), and CDD/CDF are emitted at levels that are orders of magnitude lower than other organic HAP, thus requiring a separate test method to be detected and measured.

We identified in the data for stripped resins and process wastewater only organic HAP (including vinyl chloride). For these emission sources, we are establishing total non-vinyl chloride organic HAP limits. We did not establish a THC limit for stripped resins and process wastewater because the data were derived from liquid samples (as opposed to gaseous samples for process vents), and no test method is available for testing THC in liquid samples.

For heat exchange systems and equipment leaks, we are setting requirements for leak detection and repair (LDAR). For heat exchange systems, we are setting a total strippable volatile organic compounds (VOC) leak action level and an alternative vinyl chloride leak action level because if either of these pollutants is detected in the cooling water or in the stripping gas, then repair of the leak will be required and will control all HAP. For equipment leaks, we are setting only a VOC leak action level because the only currently EPA approved leak detection method is EPA Method 21, which measures VOC. Like heat exchange systems, if the VOC leak is detected, then repair of the leak will be required and result in control of all HAP. (See preamble section V.C for further discussion regarding the pollutants regulated.)

1. Process Vents

In the proposed and final rule, we calculated the MACT floor emission levels for process vents accounting for variability using a 99-percent upper predictive limit (UPL) calculation. In the final rule, we used a 99-percent UPL calculation, but we changed the value for the number of samples used in the compliance average (the m value) in the UPL calculation for THC to 3 instead of 30 to reflect the actual number of THC test runs that will comprise the compliance average.

Tables 1 and 2 of this preamble present the final process vent emission limits for existing sources and new sources, respectively, compared to the proposed limits.

TABLE 1—COMPARISON OF PROPOSED AND FINAL EMISSION LIMITS FOR PROCESS VENTS AT EXISTING MAJOR SOURCES

Pollutant	Emission limits [a]		
	Proposed	Final: PVC-only	Final: PVC-combined
Vinyl chloride	0.32 ppmv	6.0 ppmv	1.1 ppmv.
Hydrogen chloride	150 ppmv	78 ppmv	380 ppmv.
Total hydrocarbons (THC)	2.0 ppmv as propane [c]	9.7 ppmv as propane	4.2 ppmv as propane.
Total organic HAP [b]	12 ppmv	56 ppmv	9.8 ppmv.
Dioxin/furans (TEQ)	0.023 ng/dscm	0.038 ng/dscm	0.051 ng/dscm.

[a] ppmv = parts per million by volume dry at 3-percent oxygen (O_2). ng/dscm = nanograms per dry standard cubic meter at 3-percent O_2.
[b] Total organic HAP is alternative compliance limit for THC.
[c] Proposed THC compliance limit.

TABLE 2—COMPARISON OF PROPOSED AND FINAL EMISSION LIMITS FOR PROCESS VENTS AT NEW MAJOR SOURCES

Pollutant	Emission limits [a]		
	Proposed	Final: PVC-only	Final: PVC-combined
Vinyl chloride	3.2 ppbv	0.56 ppmv	0.56 ppmv.
Hydrogen chloride	0.17 ppmv	0.17 ppmv	1.4 ppmv.
Total hydrocarbons (THC)	2.0 ppmv as propane [c]	7.0 ppmv as propane	2.3 ppmv as propane.
Total organic HAP [b]	0.22 ppmv	5.5 ppmv	5.5 ppmv.
Dioxin/furans (TEQ)	0.0087 ng/dscm	0.038 ng/dscm	0.034 ng/dscm.

[a] ppmv = parts per million by volume dry at 3-percent O_2. ng/dscm = nanograms per dry standard cubic meter at 3-percent O_2.
[b] Total organic HAP is alternative compliance limit for THC.
[c] Proposed THC compliance limit.

2. Equipment Leaks

In the proposed rule, we required reciprocating pumps, reciprocating and rotating compressors and agitators to be equipped with double seals or the equivalent. In the final rule, we are also allowing affected sources to comply with the requirements for reciprocating pumps, reciprocating and rotating compressors and agitators by complying with the requirements for 40 CFR part 63, subpart UU. If double mechanical seals, or the equivalent, are not used, 40 CFR part 63, subpart UU requires pumps to be monitored monthly at a leak definition of 1,000 parts per million (ppm); agitators must be monitored monthly at a leak definition of 10,000 ppm, and compressors must either be leakless (i.e., operating with an instrument reading of less than 500 ppm above background) or be equipped with a system to capture and transport leaks through a closed vent system to a control device.

3. Stripped Resin

In the proposed rule, we calculated concentration values for HAP in the dispersion resin subcategory using the reported mass-based values (for HAP present in the resin) and the dispersion resin production for each facility. The concentration values were then used to calculate the MACT floor emission limits for dispersion resin. For the final rule, we used the original vinyl chloride and other organic HAP concentration values, as measured and analyzed, as the basis for setting the MACT floors. This change is consistent with how we set the MACT floors for the other resin subcategories and provides a more accurate basis for setting concentration-based limits.

At proposal, vinyl chloride and total HAP limits for stripped resins were calculated using a 99-percent UPL calculation based on 30 days of vinyl chloride and other HAP data from all facilities that conducted resin sampling and analysis as part of our August 21, 2009, CAA section 114 survey and testing request for the PVC industry. The vinyl chloride stripped resin limits were calculated using data obtained from resin sampling using EPA SW–846 Method 8260B.

For the final rule, vinyl chloride limits for stripped resins were calculated based on 4 years of vinyl chloride compliance data, submitted by the PVC industry after proposal, that were obtained by resin sampling using EPA Method 107. This revision was made because EPA Method 107 is a better measure than EPA SW–846 Method 8260B of the concentration of vinyl chloride in PVC resin, as explained further in section V.E of this preamble. Furthermore, because of the significantly larger dataset of vinyl chloride concentrations measured using EPA Method 107, we calculated the final stripped resin vinyl chloride limits using a percentile for the top 5 sources. Percentiles represent the specified slice of the sample data and unlike confidence and prediction intervals, they are distribution-free.

In the proposed rule, the total HAP limits for the stripped resin subcategories included the contribution from vinyl chloride. In the final rule, vinyl chloride concentrations were removed from the total organic HAP limit calculations, resulting in total non-vinyl chloride organic HAP limits for all subcategories of stripped resin. This change was made because we have established separate limits for vinyl chloride in stripped resin and we are requiring compliance with those limits using EPA Method 107. The total non-vinyl chloride organic HAP limits are based on concentration data for all measured organic HAP, excluding vinyl chloride, collected using EPA SW–846 Methods 8015C, 8260B, 8270D and 8315A. Additional discussion is provided in section V.D of this preamble and in the memorandum, *Revised Maximum Achievable Control Technology (MACT) Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* which is available in the docket.

At proposal, variability in the total HAP limits was assessed using a 99-percent UPL calculation where the m value was set at 30 to represent 30 single daily total HAP values. For the final rule, variability was assessed in the total non-vinyl chloride organic HAP limits using the 99-percent UPL calculation and an m value of 1 to represent monthly compliance, as

explained further in section V of this preamble.

For the final rule, we excluded information from several facilities from the MACT floor analysis due to the use of inconsistent test methods, inaccurate or questionable method detection levels (MDL), or lack of documentation on the sampling and analysis results. The changes made to the MACT floor calculations are discussed in section V.E.2 of this preamble.

Tables 3 through 7 of this preamble present the proposed and final stripped resin emission limits for bulk resin, dispersion resin, suspension resin, suspension blending resin and copolymer resin, respectively, at existing and new sources.

TABLE 3—COMPARISON OF PROPOSED AND FINAL EMISSION LIMITS FOR BULK RESIN AT EXISTING AND NEW MAJOR SOURCES

Source	Pollutant	Bulk resin	
		Proposed emission limits (ppmw) [a]	Final emission limits (ppmw) [a]
Existing	Vinyl Chloride	7.1	7.1
	Total Non-Vinyl Chloride Organic HAP	170	170
New	Vinyl Chloride	7.1	7.1
	Total Non-Vinyl Chloride Organic HAP	170	170

[a] At proposal, the total organic HAP limit included vinyl chloride. The final total non-vinyl chloride organic HAP limit excludes vinyl chloride.

TABLE 4—COMPARISON OF PROPOSED AND FINAL EMISSION LIMITS FOR DISPERSION STRIPPED RESIN AT EXISTING AND NEW MAJOR SOURCES

Source	Pollutant	Dispersion resin	
		Proposed emission limits (ppmw) [a]	Final emission limits (ppmw) [a]
Existing	Vinyl Chloride	55	1300
	Total Non-Vinyl Chloride Organic HAP	110	240
New	Vinyl Chloride	41	480
	Total Non-Vinyl Chloride Organic HAP	58	66

[a] At proposal, the total organic HAP limit included vinyl chloride. The final total non-vinyl chloride organic HAP limit excludes vinyl chloride.

TABLE 5—COMPARISON OF PROPOSED AND FINAL EMISSION LIMITS FOR SUSPENSION STRIPPED RESIN AT EXISTING AND NEW MAJOR SOURCES

Source	Pollutant	Suspension resin	
		Proposed emission limits (ppmw) [a b]	Final emission limits (ppmw) [a b]
Existing	Vinyl Chloride	0.48	37
	Total Non-Vinyl Chloride Organic HAP	76	670
New	Vinyl Chloride	0.20	7.3
	Total Non-Vinyl Chloride Organic HAP	42	15

[a] At proposal, suspension resin was included in the "all other resins" subcategory.
[b] At proposal, the total organic HAP limit included vinyl chloride. The final total non-vinyl chloride organic HAP limit excludes vinyl chloride.

TABLE 6—EMISSION LIMITS FOR SUSPENSION BLENDING STRIPPED RESIN AT EXISTING AND NEW MAJOR SOURCES

Source	Pollutant	Suspension blending resin	
		Proposed Emission limits (ppmw) [a b]	Final emission limits (ppmw) [a b]
Existing	Vinyl Chloride	0.48	140
	Total Non-Vinyl Chloride Organic HAP	76	500
New	Vinyl Chloride	0.20	140
	Total Non-Vinyl Chloride Organic HAP	42	500

[a] At proposal, suspension blending resin was included in the "all other resins" subcategory.
[b] At proposal, the total organic HAP limit included vinyl chloride. The final total non-vinyl chloride organic HAP limit excludes vinyl chloride.

TABLE 7—COMPARISON OF PROPOSED AND FINAL EMISSION LIMITS FOR COPOLYMER STRIPPED RESIN AT EXISTING AND NEW MAJOR SOURCES

Source	Pollutant	Copolymer resin	
		Proposed emission limits (ppmw) [a b]	Final emission limits (ppmw) [a b]
Existing	Vinyl Chloride	0.48	790
	Total Non-Vinyl Chloride Organic HAP	76	1,900
New	Vinyl Chloride	0.20	790
	Total Non-Vinyl Chloride Organic HAP	42	1,900

[a] At proposal, copolymer resins were included in the "all other resins" subcategory.
[b] At proposal, the total organic HAP limit included vinyl chloride. The final total non-vinyl chloride organic HAP limit excludes vinyl chloride.

4. Wastewater

In the proposed rule, the wastewater limits applied to both process wastewater and maintenance wastewater. The final rule contains vinyl chloride and total non-vinyl chloride organic HAP limits for process wastewater, and requires compliance with the National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry (Hazardous Organic NESHAP or HON) maintenance wastewater provisions for maintenance wastewater at affected sources. For the proposed rule, the wastewater vinyl chloride concentration limits were calculated using a 99-percent UPL calculation with an m value of 1 to represent monthly compliance. The limits were calculated based on data reported in survey responses from companies responding to our August 21, 2009, CAA section 114. For the final rule, we recalculated the monthly vinyl chloride concentration limits for process wastewater using a 99-percent UPL calculation, as described above, but the limits were calculated based on 1 year of daily sampling data provided by the industry after proposal.

In the proposed rule, total HAP emission limits were based on a beyond-the-floor option of complying with the HON flow rate and concentration limits for wastewater. The proposed total HAP limits also included vinyl chloride. For the final rule, we calculated a total non-vinyl chloride organic HAP emission limit for process wastewater instead of a total HAP limit, with compliance demonstrated on a monthly basis. The total non-vinyl chloride organic HAP limits for process wastewater are based on information and data provided by industry in response to the August 21, 2009, CAA section 114 survey, corrections to those data provided by the PVC industry during the public comment period, and supplemental resin sampling data provided during the public comment period by one PVC manufacturer.

Table 8 of this preamble presents the proposed and final emission limits for process wastewater at existing and new sources.

TABLE 8—COMPARISON OF PROPOSED AND FINAL EMISSION LIMITS FOR PROCESS WASTEWATER AT EXISTING AND NEW SOURCES

Source	Pollutant	Proposed emission limits (ppmw)	Final emission limits (ppmw)
Existing	Vinyl Chloride	Less than 10 ppmw for streams that do not require treatment, or 0.11 ppmw for streams that require treatment [a].	6.8
	Total Non-Vinyl Chloride Organic HAP.	Less than 1,000 ppmw or less than 10 liters per minute annual average flow rate for streams that do not require treatment, or the provisions of 40 CFR part 63, subpart G for streams that require treatment [b].	110
New	Vinyl Chloride	Less than 10 ppmw for streams that do not require treatment, or 0.0060 ppmw for streams that require treatment [a].	0.28
	Total Non-Vinyl Chloride Organic HAP.	Less than 1,000 ppmw or less than 10 liters per minute annual average flow rate for streams that do not require treatment, or the provisions of 40 CFR part 63, subpart G for streams that require treatment [b].	0.018

[a] At proposal, if a wastewater stream contained a vinyl chloride concentration greater than 10 ppmw at the point of generation, then treatment was required.
[b] At proposal, if a wastewater stream contained a HAP concentration (based on HAP listed in Table 9 to part 63, subpart G) less than 1,000 ppmw or an annual average flow rate less than 10 liters per minute, then treatment was not required.

5. Heat Exchange Systems

We proposed that affected sources would have the option of using the Texas Commission on Environmental Quality (TCEQ) Modified El Paso Method or EPA SW–846 Method 8021B to monitor for leaks of VOC in their heat exchange system cooling water. For new affected sources, we proposed a total strippable VOC leak action level of 2.3 parts per million by volume (ppmv) (as methane) in the stripping gas or 30 parts per billion by weight (ppbw) in the cooling water, with monitoring every 12 hours. For existing affected sources, we proposed a total strippable VOC leak action level of 2.9 ppmv (as methane) in the stripping gas or 38 ppbw in the cooling water, with monthly monitoring. Our proposed delay of repair action levels for new and existing sources were a total strippable VOC leak action level of 29 ppmv (as methane) in the stripping gas or 380 ppbw in the cooling water.

In the final rule, we are requiring monthly cooling water monitoring for

either total strippable VOC or for vinyl chloride. Total strippable VOC monitoring must be done using either the TCEQ Modified El Paso Method or EPA Method 624, and vinyl chloride monitoring must be done using EPA Method 107, as it is the established method for the PVC industry to analyze vinyl chloride concentrations in water samples. The leak action levels for new and existing sources are the same in the final rule. Furthermore, the leak action levels and delay of repair action levels are the same whether facilities monitor for strippable VOC or for vinyl chloride in the cooling water and are 50 ppbw and 500 ppbw, respectively. For total strippable VOC monitoring using the TCEQ Modified El Paso Method, the leak action level is 3.9 ppmv in the stripping gas and the delay of repair action level is 39 ppmv. Table 9 of this preamble presents the proposed and final standards for heat exchange systems at existing and new sources.

TABLE 9—COMPARISON OF PROPOSED AND FINAL STANDARDS FOR HEAT EXCHANGE SYSTEMS AT EXISTING AND NEW SOURCES

Source	Pollutant	Proposed leak action level	Proposed monitoring frequency	Final leak action level	Final monitoring frequency
Existing	Total strippable VOC	38 ppbw in cooling water or 2.9 ppmv in stripping gas.	Monthly	50 ppbw in cooling water or 3.9 ppmv in stripping gas.	Monthly.
	Vinyl chloride	NA	NA	50 ppbw in cooling water	Monthly.
New	Total strippable VOC	30 ppbw in cooling water or 2.3 ppmv in stripping gas.	Every 12 hours	50 ppbw in cooling water or 3.9 ppmv in stripping gas.	Monthly.
	Vinyl chloride	NA	NA	50 ppbw in cooling water	Monthly.

NA—not applicable.

We have clarified in the final rule that heat exchange systems that are in HAP service and that have a maximum cooling water flow rate of greater than 10 gallons per minute are required to monitor for leaks.

6. Other Emission Sources

In addition to proposing requirements for reactor opening losses in the proposed rule, we solicited comment and additional information on emissions, controls and costs of controls for gasholders. Based on our review of comments, and analysis of methods to control emissions from gasholders, the final rule requires that emissions from gasholder vents be routed back into the process or vented through a closed vent system to a control device. Affected sources must also install floating objects on gasholder water seals to reduce emissions of vinyl chloride and other HAP from those seals.

D. Initial and Continuous Compliance, and Recordkeeping and Reporting

The final rule contains several changes to the compliance, recordkeeping and reporting requirements.

1. Process Vents

At proposal, affected sources were required to conduct performance tests for process vents on an annual basis. In the final rule, performance tests must be conducted once every 5 years since the continuous parametric monitoring requirements ensure compliance on a continuous basis.

In the final rule, we have established two subcategories for process vents: PVC-only and PVC combined. As at proposal, the final rule also requires that all gaseous streams from process vents must be routed into a closed vent system and sent to a control device in order to meet the PVC-only or PVC-combined emission limits. We are also requiring that each process vent stream must be characterized by developing an emission profile. This is to ensure that process vent streams are serving a valid process purpose and are not being diluted prior to control. We expect facilities to already have inventories and previous test results available to develop their emissions profile. All of the facilities that provided information in response to the August 21, 2009, PVC CAA section 114 survey, developed emission profiles. Additionally, we are allowing the emissions profile to be based on engineering assessment or measurement. Because of these reasons, we do not anticipate additional burden from this requirement. We have also clarified the definitions for process vent, continuous process vent, batch process vent and have added a definition for miscellaneous vent. These revised and new definitions are described in more detail in section V.I of this preamble.

In the proposed rule, new affected sources were required to install and operate CDD/CDF continuous emission monitoring systems (CEMS) after the promulgation of a performance specification. New sources were also required to install and operate HCl CEMS. The requirements to install and operate CDD/CDF CEMS and HCl CEMS have been removed as requirements since the continuous parameter monitoring system (CPMS) requirements are sufficient but both CEMS remain available as options to existing and new affected sources when the specifications are promulgated.

2. Stripped Resins

In the proposed rule, affected sources were required to demonstrate compliance with the vinyl chloride limits for stripped resin using EPA SW–846 Method 8260B. In the final rule, affected sources must demonstrate compliance with the vinyl chloride stripped resin limit using EPA Method 107 because it is a better measure of the concentration of vinyl chloride in resin and was specifically developed to be used to measure vinyl chloride concentration in stripped PVC resins. The final rule requires affected sources to demonstrate compliance with a total non-vinyl chloride organic HAP limit using the combination of four EPA SW–846 Methods: 8015C, 8260B, 8270D and 8315A.

In the final rule, we have removed all requirements for continuous parametric monitoring of resin strippers. Our rationale for this is explained in detail in section V.F.3 of this preamble.

3. Wastewater

The final rule contains separate requirements for process wastewater and maintenance wastewater. For process wastewater, we removed the requirement that a wastewater stream must be treated and meet certain HON requirements if its flow rate is greater than or equal to 10 liters per minute or contains a total HAP concentration greater than 1,000 parts per million by

weight (ppmw). Instead, affected sources must initially test all untreated process wastewater streams and meet the vinyl chloride and total non-vinyl chloride organic HAP limits in the final rule prior to discharge. We have clarified the requirements for process wastewater including the requirements for determining which streams require treatment to meet the process wastewater emission limits. Consequently, we have removed the terms "point of generation" and "point of determination" from the final rule.

In the proposed rule, affected sources were required to determine the concentration of vinyl chloride and total HAP on a monthly basis for streams that did not require treatment to ensure that their HAP concentrations remained below the applicability criteria. For the final rule, affected sources are required to determine the concentration of vinyl chloride and total non-vinyl chloride organic HAP on an annual basis for streams that do not require treatment.

In the final rule, we have added a requirement that affected sources must comply with the HON maintenance wastewater compliance requirements of 40 CFR 63.105 of subpart F.

In the final rule, we have removed all requirements for continuous parametric monitoring of wastewater steam strippers. Our rationale for this is explained in detail in section V of this preamble.

4. Heat Exchange Systems

We proposed that affected sources would have the option of using the TCEQ Modified El Paso Method or EPA SW–846 Method 8021B to monitor for leaks of VOC in their heat exchange system cooling water. In the final rule, we have retained the option to monitor total strippable VOC in the stripping gas using the TCEQ Modified El Paso Method, but for cooling water monitoring, we are requiring EPA Method 624. The final rule also includes an option for facilities to monitor their cooling water for vinyl chloride using EPA Method 107. The final rule requires the same leak action level for both new and existing sources, depending on which monitoring method is used.

5. Other Emission Sources

In the final rule, we are requiring emissions from gasholder vents be routed back into the process or vented through a closed vent system to a control device meeting the compliance requirements for process vents. To minimize fugitive emissions from gasholder water seals, we are also requiring the use of floating objects on the surface of water seals. Affected sources must establish operating procedures for use of floating devices in gasholders. These operating procedures must describe how the floating objects will be maintained to ensure a reduction in fugitive emissions from the gasholder's water seal.

E. Area Source Requirements

We proposed GACT standards for PVC area sources based on the proposed MACT standards for major sources. For the final rule, we have updated our analysis of area source GACT, considering comments received, including our analysis of cost considerations. Our revised GACT analysis assesses each PVC emission point (*e.g.*, process vents, stripped resin, equipment leaks, etc.) individually, for both existing and new sources, to determine the appropriate level of control considering cost and emission reduction. The GACT analysis was conducted for the same subcategories as major sources. A discussion of the GACT analysis is presented in section V.H of this preamble.

We have determined emission limits based on the control level that area sources are currently meeting to be GACT for existing and new area sources for PVC-only process vents, PVC-combined process vents, bulk resin, suspension resin, and process and maintenance wastewater. For other resin subcategories (*i.e.*, dispersion, suspension blending and copolymer), no existing area source produces these resins. For the dispersion subcategory, we determined GACT based on the least-controlled major source control level at existing major sources in that subcategory. GACT for the suspension blending and copolymer subcategories is based on the existing major source control levels for the single facility in each subcategory from which we determined the MACT floors. For all other emission points, *i.e.*, equipment leaks, heat exchange systems and other emission sources, we have determined that GACT should be the same work practice standards being adopted as MACT for major sources. We are also adopting the same testing and monitoring requirements that apply to major sources. Major source requirements are discussed in section IV of this preamble.

F. New and Revised Definitions

Several definitions were revised and added in the final rule as a result of new subcategories and other changes. The following definitions have been revised since the proposal: Batch process vent, conservation vent, continuous process vent, grade, in HAP service, polyvinyl chloride, polyvinyl chloride and copolymers production process unit or PVCPU, polyvinyl chloride copolymer, pressure relief device (PRD), process vent, solution process, surge control vessel, treatment process, type of resin and wastewater.

The following definitions have been added in the final rule: Gasholder, heat exchanger exit line, maintenance wastewater, miscellaneous vent, polyvinyl chloride homopolymer, process wastewater, process wastewater treatment system, PVC-combined process vent, PVC-only process vent, suspension blending process, table 10 HAP, total non-vinyl chloride organic HAP and wastewater stream. The rationale for revising and adding the definitions is provided in section V.I of this preamble.

IV. Summary of the Final Rules

A. What is the affected source?

The final rules apply to owners or operators of PVCPU located at both major source and area sources of HAP emissions, as defined in 40 CFR 63.2. The subparts apply to each affected source, where the affected source is the facility wide collection of PVCPU, storage tanks, surge control vessels, heat exchange systems, wastewater and process wastewater treatment systems that are associated with producing PVC. A new affected source is one for which construction commenced after May 20, 2011, at a Greenfield facility or at an existing facility that did not previously produce PVC prior to May 20, 2011. If components of an existing affected source are replaced, such that the replacement meets the definition of reconstruction in 40 CFR 63.2 and the reconstruction commenced after May 20, 2011, then the existing source becomes a reconstructed source and is subject to the relevant standards for a new affected source. The reconstructed source must comply with the requirements for a new affected source upon initial startup of the reconstructed source, or by April 17, 2012, whichever is later.

A PVCPU is defined as a collection of process components assembled and connected by hard-piping or duct work, used to process raw materials and to manufacture polyvinyl chloride and/or polyvinyl chloride copolymers. The collection of process components includes polymerization reactors, resin stripping operations, resin blend tanks, resin centrifuges, resin dryers, resin product separators, recovery devices, reactant and raw material charge vessels and tanks, holding tanks, mixing and weighing tanks, finished resin product

loading operations, connected ducts and piping, combustion, recovery, or recapture devices or systems and equipment (*i.e.*, all pumps, compressors, agitators, PRD, sampling connection systems, open-ended valves or lines, valves, connectors and instrumentation systems that are associated with the PVCPU). A PVCPU does not include chemical manufacturing process units, as defined in 40 CFR 63.101, which produce VCM or other raw materials used in the production of PVC.

B. When must I comply with the major and area source standards?

Existing major affected sources are required to comply with 40 CFR part 63, subpart HHHHHHH and existing area affected sources are required to comply with 40 CFR part 63, subpart DDDDDD no later than April 17, 2015. New major and area affected sources are required to comply on April 17, 2012, or upon startup, whichever is later.

C. What is the relationship between this final rule for major sources and the 40 CFR part 61, subpart F standards?

Affected sources are currently subject to requirements in the part 61 NESHAP. This final rule includes requirements that are at least as stringent as the requirements in the part 61 NESHAP. Thus, once an affected source is in compliance with 40 CFR part 63, subpart HHHHHHH, the requirements of the part 61 NESHAP will no longer apply.

D. Are there subcategories for major sources?

The final rule contains two subcategories for process vents. The process vent subcategories are based on whether the vent streams are collected from: (1) Only PVC production processes (*i.e.*, PVC-only process vents) or (2) PVC production process and other non-PVC production processes, such as VCM or EDC manufacturing (*i.e.*, PVC-combined process vents).

The final rule contains five subcategories for limits on the amount of HAP remaining in resin following polymerization and stripping (*i.e.*, the stripped resin). The stripped resin subcategories are based on the type of resin produced, and include the following homopolymer resins: (1) Bulk resin, (2) dispersion resin, (3) suspension blending resin and (4) suspension resin. A fifth subcategory is included in the final rule for all copolymer resins.

See section V.D of this preamble for more discussion on subcategories.

E. What emission standards must I meet for major sources?

This rule establishes requirements for affected sources located at or part of a major source of HAP emissions. We explain our rationale for the finalized standards in section V.E of this preamble.

1. Storage Vessels and Handling Operations

Under 40 CFR 63.11910 and Table 3 of the final rule, if you own or operate a storage vessel at a new or existing affected source, we are requiring that material stored with a maximum true vapor pressure of greater than 11.1 pounds per square inch absolute (psia) be stored in pressure vessels with no emissions to the atmosphere. During those times when purging is required or when the pressure vessel is being loaded, the purged stream or the emission stream during loading is required to be routed to a closed vent system and control device. The closed vent system and control device must meet the requirements specified in 40 CFR 63.11925 through 40 CFR 63.11950 of the final rule. You are also required to equip all openings in the pressure vessel with closure devices that are designed to operate with no detectable emissions, as determined using procedures specified in 40 CFR 63.11910(c)(3) of the final rule.

For storage vessels with a capacity greater than or equal to 40,000 gallons that store material with a maximum true vapor pressure greater than or equal to 0.75 psia or storage vessels with a capacity greater than or equal to 20,000 gallons (but less than 40,000 gallons) that store materials with a maximum true vapor pressure greater than or equal to 4 psia, we are requiring compliance with one of two equivalent compliance options. We are requiring that material be stored in either: (1) A floating roof tank meeting the operating, inspection and maintenance requirements of 40 CFR part 63, subpart WW, or (2) a fixed roof storage vessel that routes vent streams to a closed vent system and control device (meeting the requirements of 40 CFR 63.11925 through 40 CFR 63.11950 of the final rule) capable of reducing inlet VOC emissions by 95 percent or greater.

We are requiring that all other storage vessels meet the operating, inspection and maintenance requirements for fixed roof vessels of 40 CFR 63.11910(a) of the final rule or comply with either the controlled fixed roof or floating roof requirements discussed previously. 40 CFR 63.11910(a)(1)(ii) and 40 CFR 63.11910(a)(3)(i) of the final rule include requirements to equip each opening in the roof with a closure device, and to perform initial and annual inspections and repair any defects found within the specified time period. Defects include, but are not limited to, visible cracks, holes, gaps or other open spaces in the closure device or between the perimeter of the opening and the closure device; broken, cracked or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps or other closure devices.

2. Equipment Leaks

In 40 CFR 63.11915 of the final rule, we are requiring that existing and new affected sources comply with the LDAR program requirements of the National Emission Standards for Equipment Leaks—Control Level 2 Standards, subpart UU of 40 CFR part 63. For valves in gas and light liquid service, subpart UU specifies a leak definition of 500 ppm VOC and a monitoring frequency that is dependent upon the number of leaking valves. Subpart UU also requires equipment specifications to prevent leaks for other pieces of equipment. We are requiring that a vinyl chloride monitoring system be operated for detection of major leaks and identification of the general area of the plant where a leak is located. A vinyl chloride monitoring system is a device that obtains air samples from one or more points continuously and analyzes the samples with gas chromatography, infrared spectrophotometry, flame ion detection or an equivalent or alternate method.

In 40 CFR 63.11915 of the final rule, we are also requiring that, in addition to operating with no detectable emissions, there be no discharge to the atmosphere from any PRD on any equipment in HAP service within the PVC affected source. We are requiring that, upon a discharge to the atmosphere from the PRD, that the monitoring requirements specified in 40 CFR part 63, subpart UU for pressure releases from PRD be followed.

3. Heat Exchange Systems

In 40 CFR 63.11920 of the final rule, we are requiring that you implement a LDAR program to detect leaks of HAP into cooling water. For both new and existing sources, we are requiring monthly monitoring for both closed loop and once-through heat exchange systems using either the TCEQ Modified El Paso Method, EPA Method 624 or EPA Method 107. The leak action level is 50 ppbw of total strippable VOC or vinyl chloride in the cooling water, or a leak action level of 3.9 ppmv in the stripping gas. The delay of repair action

level for both new and existing sources is 500 ppbw of total strippable VOC or vinyl chloride in the cooling water, or 39 ppmv of VOC in the stripping gas. When a leak is identified, additional monitoring must be performed to isolate the source of the leak. If the total strippable VOC or vinyl chloride concentration remains below the applicable leak action level throughout the period of additional monitoring, then repairs are not required; otherwise, repairs must be completed within 45 days of identifying the leak. Repairs may be delayed if the concentration of total strippable VOC or vinyl chloride in the cooling water remains below the delay of repair action level and either: (1) It is technically infeasible to repair the leak without a shutdown, or (2) the necessary equipment, parts or personnel are not available.

4. Process Vents

In 40 CFR 63.11925 of the final rule, we are requiring all process vents be routed to a closed vent system and control device meeting the emission standards in Table 10 of this preamble. All process vents must meet the emission standards, including continuous process vents, batch process vents and miscellaneous vents.

We are requiring the emission limitations presented in Table 10 of this preamble for two subcategories of process vents at major sources: (1) PVC-only process vents and (2) PVC-combined process vents. These emission limits apply at all times.

TABLE 10—EMISSION LIMITS FOR PROCESS VENTS AT EXISTING AND NEW MAJOR SOURCES

Subcategory	Pollutant	Emission limitations [a]	
		Existing sources	New sources
PVC-only process vents	Vinyl chloride	6.0 ppmv	0.56 ppmv.
	Hydrogen chloride	78 ppmv	0.17 ppmv.
	Total hydrocarbons (THC) [b]	9.7 ppmv as propane	7.0 ppmv as propane.
	Total organic HAP [b]	56 ppmv	5.5 ppmv.
	Dioxin/Furans (TEQ)	0.038 ng/dscm	0.038 ng/dscm.
PVC-combined process vents	Vinyl chloride	1.1 ppmv	0.56 ppmv.
	Hydrogen chloride	380 ppmv	1.4 ppmv.
	Total hydrocarbons (THC) [b]	4.2 ppmv as propane	2.3 ppmv as propane.
	Total organic HAP [b]	9.8 ppmv	5.5 ppmv.
	Dioxin/Furans (TEQ)	0.051 ng/dscm	0.034 ng/dscm.

[a] ppbv = parts per billion by volume dry at 3-percent oxygen (O_2). ppmv = parts per million by volume dry at 3-percent O_2. ng/dscm = nanograms per dry standard cubic meter at 3-percent O_2.
[b] Total organic HAP is an alternative compliance limit for THC.

5. Other Emission Sources

Other emission sources include reactor and other component opening losses and gasholders. When reactors or other components (including pre-polymerization reactors used in the manufacture of bulk resin) are opened for cleaning, we are requiring in 40 CFR 63.11955 of the final rule that emissions be minimized prior to opening. We are requiring that emissions from opening a polymerization reactor must not exceed 0.04 pound vinyl chloride/ton of polyvinyl chloride product where the product means the gross product of pre-polymerization and post-polymerization. We are requiring emissions from opening of process components for any reason be minimized by reducing the volume of vinyl chloride to an amount that occupies a volume of no more than 2.0 percent of the component's containment volume or 25 gallons, whichever is larger, at standard temperature and pressure. Any vinyl chloride emissions resulting from opening equipment must be ducted through a closed vent system to a control device meeting the process vent limits of the final rule. The outlet of the control device must meet the emission limitations for process vents discussed in section IV.E.4 of this preamble.

In 40 CFR 63.11955 of the final rule, we are requiring that emissions from gasholders must either be routed back into the process or be vented to a closed vent system and control device from which the exhaust gases do not exceed the process vent limits. To minimize fugitive emissions from gasholder water seals, we are also requiring the use of floating objects on the surface of the water seal. Each gasholder must operate with one or more types of objects installed on the surface of the water seal to reduce emissions from those seals, including floating balls, hollow floating disks, an oil layer and/or floating mats.

6. Stripped Resin

In 40 CFR 63.11960 of the final rule, we are setting emission limits for vinyl chloride and total non-vinyl chloride organic HAP for five subcategories of stripped resins, as presented in Tables 11 and 12 of this preamble. The limits were developed for new and existing affected sources, based on the type of resin produced. Subcategories for homopolymer resins are: (1) Bulk resin, (2) dispersion resin, (3) suspension blending resin and (4) suspension resin. A fifth subcategory is included in the final rule for copolymer resin. These emission limits would apply at all times.

TABLE 11—LIMITS FOR STRIPPED RESINS AT EXISTING MAJOR SOURCES

Pollutant	Emission limits (ppmw)				
	Homopolymer resins				Copolymer resin
	Bulk resin	Dispersion resin	Suspension resin	Suspension blending resin	
Vinyl chloride	7.1	1,300	37	140	790

TABLE 11—LIMITS FOR STRIPPED RESINS AT EXISTING MAJOR SOURCES—Continued

Pollutant	Emission limits (ppmw)				
	Homopolymer resins				Copolymer resin
	Bulk resin	Dispersion resin	Suspension resin	Suspension blending resin	
Total non-vinyl chloride organic HAP	170	240	670	500	1,900

TABLE 12—LIMITS FOR STRIPPED RESINS AT NEW MAJOR SOURCES

Pollutant	Emission limits (ppmw)				
	Homopolymer resins				Copolymer resin
	Bulk resin	Dispersion resin	Suspension resin	Suspension blending resin	
Vinyl chloride	7.1	480	7.3	140	790
Total non-vinyl chloride organic HAP	170	66	15	500	1,900

7. Wastewater

In 40 CFR 63.11965 of the final rule, we are requiring process wastewater streams at existing sources to meet emission limits of 6.8 ppmw for vinyl chloride and 110 ppmw for total non-vinyl chloride organic HAP before being exposed to the atmosphere, discharged from the affected source or discharged from the affected source untreated as wastewater. Process wastewater streams at new sources are required to meet emission limits of 0.28 ppmw for vinyl chloride and 0.018 ppmw for total non-vinyl chloride organic HAP before being exposed to the atmosphere, discharged from the affected source or discharged from the affected source untreated as wastewater. Pollutant concentrations in each process wastewater stream at existing and new sources must be measured immediately as the process wastewater stream leaves a process component, before being exposed to the atmosphere and before mixing with any other wastewater stream.

The final rule contains separate requirements for maintenance wastewater. Maintenance wastewater must meet the requirements of 40 CFR 63.105.

F. What are the initial and continuous compliance requirements for major sources?

In 40 CFR 63.11896 of the final rule, we are requiring that, if you make a process change to an existing affected source that does not meet the criteria to become a reconstructed affected source in 40 CFR 63.11870(e) of the final rule, you must be in compliance for any added or changed emission points by the compliance date for existing affected sources. If the process change occurs after the compliance date for existing sources, then the added or changed emissions point must be in compliance upon startup. If the process change results in a change in the characteristics of any emission point such that a different emission standard or operating parameter limit applies, we are requiring that you demonstrate that the changed emission point complies with the applicable requirements for an existing affected source. You must demonstrate compliance with any emission limits and establish applicable operating limits by 180 days after the compliance date for existing affected sources; if the startup of the changed emission point occurs after the compliance date for existing affected sources, then you must demonstrate compliance with any emission limits and establish applicable operating limits by 180 days after the date of initial startup of the changed emission point.

We are also requiring that, if you make a process change to a new affected source, you demonstrate that any added emission points are in compliance with the applicable standards for a new affected source by startup of the changed emission point. You must also demonstrate initial compliance with any emission limits and establish applicable operating limits by 180 days after the date of initial startup of the changed process unit.

If you make a process change that adds or changes emission points, we are requiring that you demonstrate continuous compliance with your emission standards and operating limits according to the procedures and frequency in 40 CFR 63.11910 through 40 CFR 63.11980 of this final rule and submit a notification report specified in 40 CFR 63.11985 of the final rule.

A facility subject to the PVC-combined process vent limits that no longer combines process vent streams from other source categories, or a facility that is subject to the PVC-only process vent limits that subsequently combines process vent streams from other source categories, is subject to the process change requirements in 40 CFR 63.11896 of the final rule. Routine and maintenance shutdowns that cause temporary cessation of the vent stream flow from other source categories are not subject to the process change requirements.

1. What are the initial and continuous compliance requirements for storage vessels?

For each floating roof storage vessel, we are requiring that you meet the operating, inspection, repair and maintenance requirements of 40 CFR part 63, subpart WW. For each fixed roof storage tank venting through a closed vent system to a control device achieving 95-percent reduction in total HAP emissions, we are requiring that you meet the requirements for closed vent systems and control devices in 40 CFR 63.11925 of the final rule and summarized in section IV.F.4 of this preamble.

In 40 CFR 63.11910 of the final rule, we are also requiring that, for each fixed roof tank, you install and maintain the tank with no visible cracks, holes or other open spaces between roof section joints or between the interface of the roof edge and the tank wall. We are also requiring that you install closure devices that you secure in the closed position except during periods when you need to have access to the interior of the fixed roof tank. The closure device may be opened during the period

needed to provide access. The fixed roof tank and its closure device are required to be inspected initially and at least once per year. The inspection requirements are not applicable to parts of the fixed roof that are determined to be unsafe to inspect if you document and explain why it is unsafe to inspect and develop a plan to conduct inspections when the tank is not in service. A first attempt to repair defects must be made no later than 5 calendar days after detection and repairs are required to be completed no later than 45 days after detection, except as specified in 40 CFR 63.11910(a)(4)(ii) of the final rule.

In 40 CFR 63.11910 of the final rule, for pressure vessels, we are requiring that all potential leak interfaces in the pressure vessel be monitored for leaks annually and repaired following the procedures of 40 CFR 63.11915 of the final rule.

2. What are the initial and continuous compliance requirements for equipment leaks?

For each applicable piece of equipment (*e.g.*, valves, connectors) associated with your affected source, we are requiring that you meet the LDAR requirements of 40 CFR part 63, subpart UU. In 40 CFR 63.11915 of the final rule, you are required to install a release indicator on each PRD that would be able to identify and record the time and duration of each pressure release and notify operators that a pressure release has occurred.

3. What are the initial and continuous compliance requirements for heat exchange systems?

We are requiring that, for each affected source, you must operate a heat exchange system monitoring program, as specified in the final rule. Under the compliance requirements for heat exchange systems in 40 CFR 63.11920 of the final rule, an affected source is required to conduct sampling and analyses for either total strippable VOC using the TCEQ Modified El Paso Method or EPA Method 624, or for vinyl chloride using EPA Method 107. Affected sources must monitor no less frequently than monthly and fix any leaks detected. We are requiring different sampling locations for once-through and closed loop heat exchange systems, as specified in 40 CFR 63.11920 of the final rule. For once-through systems only, you may monitor at the cooling tower return line prior to exposure to the air or you may monitor the inlet water feed line prior to any heat exchange. If multiple heat exchange systems use the same water feed (*i.e.*, inlet water from the same primary water source), you may monitor at one representative location and use the monitoring results for that sampling location for all heat exchange systems that use that same water feed. For once-through systems, you must monitor selected heat exchanger exit line(s) so that each heat exchanger or group of heat exchangers within a system is covered by the selected monitoring location. Monitoring of selected heat exchanger exit lines is also a monitoring option for closed loop systems.

We are exempting a heat exchange system from the monitoring requirements in 40 CFR 63.11920 if all heat exchangers within the heat exchange system operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side, the heat exchange system does not contain any heat exchangers that are in HAP service, or the heat exchange system has a maximum cooling water flow rate of 10 gallons per minute or less.

Identified leaks must be repaired as soon as practicable, but within 45 days after identifying the leak. We are allowing delay of repair as long as the total strippable VOC concentration is below 39 ppmv in the stripping gas or below 500 ppbw in the cooling water, or the vinyl chloride concentration in the cooling water is below 500 ppbw and other criteria are met. Specifically, leaking heat exchanger repairs may be delayed if the repair is technically infeasible without a shutdown or the necessary equipment, parts or personnel are not available. To delay repairs in either case, the total strippable VOC or vinyl chloride concentration must initially be, and remain less than, the delay of repair action level for all monitoring periods during the delay of repair.

4. What are the initial and continuous compliance requirements for process vents?

To demonstrate compliance for process vents, you are required to meet the requirements of final 40 CFR 63.11930 for each closed vent system that routes emissions from process vents to a control device. You are required to meet the initial and continuous compliance requirements for process vents specified in 40 CFR 63.11925 and 40 CFR 63.11935, the monitoring requirements for your process vent control device, as specified in 40 CFR 63.11940 and the performance testing requirements for process vents in 40 CFR 60.11945. You may not use a flare to comply with the emission limits of the final rule, as specified in 40 CFR 63.11925(b).

As specified in 40 CFR 63.11925(g), affected sources are required to characterize their process vents by developing an emission profile that describes the characteristics of the process vent stream under either absolute or hypothetical worst-case conditions. In 40 CFR 63.11950, we have provided equations to develop the emissions profile for each batch process vent, including equations for vapor displacement, gas sweep of a partially filled vessel, heating, depressurization, vacuum systems, gas evolution, air drying and purging. All other emissions or emissions episodes for the emissions profile would be determined through an engineering assessment or through testing approved by the Administrator. See 40 CFR 63.11950(i) of the final rule.

Closed vent systems. In 40 CFR 63.11930 of the final rule, for closed vent systems, you are required to meet specified design requirements and install flow indicators in the bypass lines or meet other requirements to prevent and detect bypass of the control device. You must also follow the inspection, leak monitoring and repair requirements in 40 CFR 63.11930 of the final rule for closed vent systems. Closed vent systems in vacuum service are required to install alarms rather than performing leak inspection and monitoring. If you operate a closed vent system in vacuum service, you are not required to comply with the other closed vent system requirements in the final rule.

Performance testing, continuous parameter monitoring system (CPMS) and continuous emission monitoring system (CEMS) requirements for process vents and associated control devices. Compliance is demonstrated through a combination of performance testing (as specified in 40 CFR 63.11925 and 40 CFR 63.11945) and/or monitoring using CPMS and/or CEMS that measure process vent control device operating parameters (as specified in 40 CFR 63.11925, 40 CFR 63.11935 and 40 CFR 63.11940). These sections also refer to Tables 1, 2, 5, 7 and 8 of the final rule for emission limits, testing methods and requirements. Below, we summarize the process vent testing and compliance requirements by pollutant. Each performance test must consist of three test runs.

We are requiring that existing and new sources demonstrate initial compliance with the THC emission limits in Table 1 or 2 of the final rule by measuring THC at the outlet of the control device using EPA Method 25A, as specified in Table 8 of the final rule.

The minimum test run duration would be 1 hour. To demonstrate continuous compliance with the THC emission limits, each control device must be tested once every 5 years using EPA Method 25A. Alternatively, existing and new sources may demonstrate initial compliance with the total organic HAP emission limits in Table 1 or 2 of the final rule by measuring total organic HAP at the outlet of the control device using EPA Method 18 and EPA Method 320. To demonstrate continuous compliance with the total organic HAP emission limits, each control device must be tested once every 5 years using EPA Method 18 and EPA Method 320.

During the initial compliance test, you are required to establish values for the control device operating parameters specified in 40 CFR 63.11935 and 40 CFR 63.11940 (*e.g.*, oxidizer temperature). You would then use a CPMS to continuously monitor that parameter to demonstrate continuous compliance with either the THC or total organic HAP limits. New and existing sources could elect to use THC CEMS instead of establishing operating limits and using CPMS to demonstrate continuous compliance for THC emission limits. All CEMS must meet the applicable performance specifications, procedures and other calibration, accuracy and operating and maintenance requirements, as specified in 40 CFR 63.11935 of the final rule.

For vinyl chloride, you are required to demonstrate compliance by conducting an initial performance test using EPA Method 18. To demonstrate continuous compliance with the vinyl chloride emission limits, each control device must be tested once every 5 years using EPA Method 18.

For CDD/CDF, you demonstrate initial compliance by conducting a performance test using EPA Method 23 and continuous compliance by conducting performance tests using EPA Method 23 once every 5 years. The minimum sampling volume collected is 5 cubic meters for EPA Method 23. For HCl, you must demonstrate compliance by conducting an initial performance test using EPA Method 26 or 26A. The minimum sampling volumes collected is 60 liters for EPA Method 26 or 1 cubic meter for EPA Method 26A. Additionally, you are required to establish operating parameters during the initial performance test and use CPMS to continuously monitor those parameters. New and existing sources are no longer required to use CEMS but have the option of using HCl and/or CDD/CDF CEMS instead of conducting continuous parametric monitoring which is sufficient to demonstrate continuous compliance, as provided in 40 CFR 63.11925 of the final rule. All CEMS must meet the applicable performance specifications, procedures and other calibration, accuracy and operating and maintenance requirements, as specified in 40 CFR 63.11935 of the final rule.

The final rule includes specific performance testing requirements, including the process operating conditions under which performance tests should be conducted, for continuous process vents and batch operations, as provided in 40 CFR 63.11945, and discussed in sections IV.F and IV.G of this preamble.

All CPMS are required to have data averaging periods of 3-hour block averages. All CPMS are required to meet minimum accuracy and calibration frequency requirements, as specified in 40 CFR 63.11935 and Table 7 of the final rule. For each monitored parameter, you must establish a minimum, maximum or a range that indicates proper operation of the control device, as specified in 40 CFR 63.11935(d). The final rule specifies the parameters that would be monitored for each type of control device, including each oxidizer, absorber, adsorber, condenser or other control device. You must also install a flow indicator at the inlet of the control device to indicate periods of no flow to the control device.

Some control devices are subject to additional emission point-specific performance testing requirements, as described in 40 CFR 63.11945 of the final rule. We have included specific performance testing requirements for continuous process vents and batch operations, as provided in 40 CFR 63.11945 of the final rule and discussed in sections IV.F and IV.G of this preamble.

5. What are the initial and continuous compliance requirements for wastewater?

As specified in 40 CFR 63.11965(b) of the final rule, we are requiring that you conduct an initial test for process wastewater streams from the affected source to determine the vinyl chloride and the total non-vinyl chloride organic HAP concentrations. You are required to use EPA Method 107 for measuring vinyl chloride and EPA SW–846 Methods 8015C, 8260B, 8270D and 8315A for measuring total non-vinyl chloride organic HAP. For process wastewater streams that are not being treated, we are requiring that you determine which of those process wastewater streams, if any, require treatment in order to meet the wastewater emission limits. You must collect one grab sample immediately as the process wastewater stream leaves a process component and before mixing with any other wastewater stream and before being exposed to the atmosphere, discharged to a wastewater treatment process or discharged untreated as wastewater.

If your process wastewater stream contains vinyl chloride concentrations greater than or equal to 6.8 ppmw at existing sources or 0.28 ppmw at new sources or total non-vinyl chloride organic HAP concentrations greater than or equal to 110 ppmw at existing sources or 0.018 ppmw at new sources, you are required to treat the wastewater stream to achieve concentrations below these levels. We are requiring that you measure at the outlet of the treatment system by collecting one grab sample each month.

In the final rule, affected sources must comply with the requirements of 40 CFR 63.105 for maintenance wastewater streams.

For more information on the wastewater compliance requirements, see 40 CFR 63.11965, 40 CFR 63.11970 and 40 CFR 63.11975 of the final rule.

6. What are the initial and continuous compliance requirements for stripped resins?

In 40 CFR 63.11960 of the final rule, we are requiring that you conduct initial performance tests to demonstrate compliance with the vinyl chloride and total non-vinyl chloride organic HAP limits for stripped resins. We are also requiring that you conduct daily sampling and testing to demonstrate continuous compliance with the vinyl chloride limit and monthly sampling and testing to demonstrate continuous compliance with the total non-vinyl chloride organic HAP limit. The tests must be conducted at the outlet of the resin stripper for continuous processes and immediately after stripping for batch processes. You are required to use EPA Method 107 for measuring vinyl chloride and EPA SW–846 Methods 8015C, 8260B, 8270D and 8315A for measuring total non-vinyl chloride organic HAP listed in Table 10 of the final rule.

To demonstrate initial compliance with the vinyl chloride and total non-vinyl chloride organic HAP limits, you are required to collect one grab sample every 8 hours for a single grade or one grab sample per grade of PVC resin produced, whichever is more frequent, for each resin stripper over a 24-hour period. You are required to collect samples over a 24-hour period that reflects the primary product being produced, based on total mass of resin

produced in the preceding 12 months. Grade is defined in 40 CFR 63.12005 of the final rule.

To demonstrate continuous compliance with the vinyl chloride limit for a continuous process, you are required to collect one grab sample from each resin stripper every 8 hours for a single grade or one grab sample per grade of PVC resin produced, whichever is more frequent. To demonstrate compliance with the vinyl chloride limit for a batch process, you are required to collect one grab sample from each batch of resin produced. You must demonstrate compliance on a daily basis using a 24-hour grade-weighted average concentration, based on production.

To demonstrate continuous compliance with the total non-vinyl chloride organic HAP limits for a continuous process, on a monthly basis, you are required to collect one grab sample every 8 hours for a single grade or per grade of PVC resin produced, whichever is more frequent from each resin stripper over a single 24-hour period. The 24-hour arithmetic average total non-vinyl chloride organic HAP concentration for each stripper for each resin grade produced during the 24-hour sampling period must be calculated using the individual HAP concentrations measured for the grab.

To demonstrate continuous compliance with the total non-vinyl chloride organic HAP limits for a batch process, on a monthly basis, you are required to collect one grab sample for each batch of resin produced over a 24-hour period. You must demonstrate compliance on a monthly basis.

7. What are the initial and continuous compliance requirements for other emission sources?

To demonstrate compliance with the requirements for other emission sources, we are requiring that prior to opening reactors and other components, you follow the initial and continuous compliance requirements of 40 CFR 63.11955. In 40 CFR 63.11955 of the final rule, we are requiring that each gasholder must either be routed back into the process or be vented to a closed vent system and control device meeting the requirements of 40 CFR 63.11925 through 63.11950. To minimize fugitive emissions from gasholder water seals, we are also requiring the use of floating objects on the surface of the water seal. Affected sources must establish operating procedures for use of floating devices in gasholders. These operating procedures must describe how the floating objects will be maintained to ensure a reduction in fugitive emissions from the gasholder's water seal.

G. What are the performance testing requirements for batch process operations at major sources?

For batch process operations, performance tests must be conducted under the most challenging conditions that you run your batch process operations to ensure that the control device(s) is/are operating at the level needed for compliance under all conditions. Subsequent to the initial compliance test, continuous monitoring of operating parameters established during the initial test is the measure of continuous compliance with the efficiency requirement under all conditions.

H. What are the notification, recordkeeping and reporting requirements at major sources?

1. Notifications and Reports

All new and existing sources are required to comply with certain requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 4 of the final 40 CFR part 63, subpart HHHHHHH. The General Provisions include specific requirements for notifications, recordkeeping and reporting. Reports include notifications of initial startup, initial notification, notification of compliance status, compliance reports, notification of performance test, notification of inspection, batch pre-compliance report and other notifications and reports specified in the final 40 CFR 63.11985.

The notification of compliance status report required by 40 CFR 63.9(h) must include certifications of compliance with rule requirements.

The excess emissions and continuous system performance report and summary report required by 40 CFR 63.10(e)(3) of the NESHAP General Provisions (referred to in the rule as a compliance report) are required to be submitted semi-annually for reporting periods during which there was: An exceedance of any emission limit or a monitored parameter; a deviation from any of the requirements in the rule; or if any process changes occurred and compliance certifications were reevaluated. The final rule includes additional requirements for what you must include in these reports for each type of emission point. See 40 CFR 63.11985 of the final rule.

2. Recordkeeping

The final rule requires compiling and retaining records to demonstrate compliance with each emission standard. These recordkeeping requirements are specified either directly in the final rule, in the General Provisions to 40 CFR part 63 and in 40 CFR part 63, subparts F, UU and WW. Records that we are requiring that you keep include performance tests, records of CPMS and CEMS, records of malfunctions, records of deviations, records specific to each emission point and other records specified in 40 CFR 63.11990. The 40 CFR part 63 General Provisions requirements that apply are listed in Table 4 of the final rule. We are requiring that records be kept for 5 years in a form suitable and readily available for EPA review. We are requiring that records be kept on site for 2 years; you may keep the records off site for the remaining 3 years. See 40 CFR 63.11990 of the final rule.

I. What are the requirements for area sources?

We are revising the existing NESHAP for PVC production area sources (40 CFR part 63, subpart DDDDDD), based on the results of our GACT analysis, as explained in section V.H of this preamble. The final rule subcategorizes process vents and stripped resin at existing and new area sources in the same manner as major sources. All new and existing sources are required to comply with requirements of the General Provisions (40 CFR part 63, subpart A), are identified in Table 4 of the final 40 CFR part 63, subpart DDDDDD. The final rule contains the same notification, reporting and recordkeeping requirements for area sources as for major sources. In the final rule, performance testing requirements at batch operations as well as process change requirements, discussed in sections IV.G and IV.F of this preamble, respectively, are the same for PVC area sources as for major sources. The final rule requires area sources to meet the following requirements:

1. Storage Vessels and Handling Operations

Storage vessel and handling operations at existing and new PVC area sources are subject to the same standards and compliance requirements as major sources, as discussed in sections IV.E.1 and IV.F.1 of this preamble.

2. Equipment Leaks

Equipment leaks at existing and new PVC area sources are subject to the same standards and compliance requirements as major sources, as discussed in sections IV.E.2 and IV.F.2 of this preamble.

3. Heat Exchange Systems

Heat exchange systems at existing and new PVC area sources are subject to the same standards and compliance requirements as major sources, as discussed in sections IV.E.3 and IV.F.3 of this preamble.

4. Process Vents

PVC-only process vents and PVC-combined process vents from existing and new PVC area sources are subject to the emission limits summarized in Table 13 of this preamble. They are also subject to the same requirements as major sources for demonstrating compliance (*e.g.*, continuous parametric monitoring, performance tests, test methods, etc.), as discussed in section IV.F.4 of this preamble.

TABLE 13—EMISSION LIMITS FOR PROCESS VENTS AT EXISTING AND NEW AREA SOURCES

Subcategory	Pollutant	Emission limits [a]	
		Existing sources	New sources
PVC-only process vents	Vinyl chloride	5.3 ppmv	5.3 ppmv.
	Total hydrocarbons (THC) [b]	46 ppmv as propane	46 ppmv as propane.
	Total organic HAP [b]	140 ppmv	140 ppmv.
	Dioxin/Furans (TEQ)	0.13 ng/dscm	0.13 ng/dscm.
PVC-combined process vents	Vinyl chloride	0.56 ppmv	0.56 ppmv.
	Total hydrocarbons (THC) [b]	2.3 ppmv as propane	2.3 ppmv as propane.
	Total organic HAP	29 ppmv	29 ppmv.
	Dioxin/Furans (TEQ)	0.076 ng/dscm	0.076 ng/dscm.

[a] ppmv = parts per million by volume dry at 3-percent oxygen (O_2).
ng/dscm = nanograms per dry standard cubic meter at 3-percent O_2.
[b] Total organic HAP is an alternative compliance limit for THC.

5. Other Emission Sources

Other emission sources include reactor and other component opening losses and gasholders. These emission sources at existing and new PVC area sources are subject to the same standards and compliance requirements as major sources, as discussed in section IV.E.5 and IV.F.7 of this preamble.

6. Stripped Resins

Stripped resins at new and existing area sources are subject to the emission limits summarized in Table 14 of this preamble. They are also subject to the same compliance requirements as major sources, as discussed in sections IV.E.6 and IV.F.6 of this preamble. The two existing area sources produce bulk and suspension resins and we have established GACT limits for those resin subcategories based on data for the two area sources. However, as discussed in section V of this preamble, existing major sources may have the potential to become synthetic area sources by taking federally enforceable permit limits before the first substantive compliance date of this rule. Therefore, we are also setting existing area source limits for dispersion resin, suspension blending resin and copolymer resin. We are also establishing limits for new area sources based on the type of resin that could potentially be produced: (1) Bulk resin, (2) dispersion resin, (3) suspension blending resin, (4) suspension resin and (5) copolymer resin.

TABLE 14—EMISSION LIMITS FOR STRIPPED RESINS AT NEW AND EXISTING AREA SOURCES

Subcategory	Pollutant	Emission limits (ppmw)	
		Existing sources	New sources
Bulk resin	Vinyl chloride	7.1	7.1
	Total non-vinyl chloride organic HAP	170	170
Suspension	Vinyl chloride	36	36
	Total non-vinyl chloride organic HAP	36	36
Dispersion	Vinyl chloride	1,500	1,500
	Total non-vinyl chloride organic HAP	320	320
Suspension blending	Vinyl chloride	140	140
	Total non-vinyl chloride organic HAP	500	500
Copolymer	Vinyl chloride	790	790
	Total non-vinyl chloride organic HAP	1,900	1,900

7. Wastewater

In the final rule, we are requiring that process wastewater streams at existing and new PVC area sources reduce the concentration of vinyl chloride and total non-vinyl chloride organic HAP, measured immediately as the process wastewater stream leaves a process component and before mixing with any other wastewater stream, to no more than the levels specified in Table 15 of this preamble. We are also requiring that wastewater streams from existing and new PVC area sources meet the same requirements for demonstrating compliance as major sources including maintenance wastewater work practices, as discussed in section IV.F.5 of this preamble.

TABLE 15—LIMITS FOR PROCESS WASTEWATER AT NEW AND EXISTING AREA SOURCES

Pollutant	Emission limits (ppmw)
Vinyl chloride	2.1
Total non-vinyl chloride organic HAP	0.018

J. What are the electronic data submittal requirements?

The EPA must have performance test data to conduct effective reviews (*e.g.*, risk assessment) of CAA section 112 standards, as well as for many other purposes, including compliance determinations, emission factor development and annual emission rate determinations. In conducting these reviews, the EPA has found it ineffective and time consuming, not only for us, but also for regulatory agencies and source owners and operators to locate, collect and submit emissions test data in paper form because of varied locations for data storage and varied data storage methods. In recent years though, stack testing firms have typically collected performance test data in electronic format, making it possible to move to an electronic data submittal system that would increase the ease and efficiency of data submittal and improve data accessibility.

In the final rule, the EPA is including a step to increase the ease and efficiency of data submittal and improve data accessibility. Specifically, we are requiring owners and operators of PVC production facilities to submit electronic copies of certain required performance test reports to the EPA's WebFIRE database. The WebFIRE database was constructed to store performance test data for use in developing emission factors. A description of the WebFIRE database is available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main*.

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

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

One major advantage of submitting source test data through the ERT is that it will provide a standardized method to compile and store much of the documentation required to be reported by this final rule. Another advantage is that the ERT clearly states what testing information is required.

Another important benefit of submitting these data to the EPA at the time the source test is conducted is that it should substantially reduce the effort involved in data collection activities in the future. When the EPA has performance test data in hand, there will likely be fewer or less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. This would result in a reduced burden on both affected facilities (in terms of reduced manpower to respond to data collection requests) and the EPA (in terms of preparing and distributing data collection requests and assessing the results).

State, local and tribal agencies may also benefit from the more streamlined and accurate review process created by an electronic review process rather than a manual data assessment, making review and evaluation of the source provided data and calculations easier and more efficient. Finally, another benefit of the data submittal to WebFIRE electronically is that these data would greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA would be able to ensure that emission factors, when updated, represent the most current range of operational practices. In summary, consistent with Executive Order 13563, *Improving Regulation and Regulatory Review*, issued on January 18, 2011, in addition to supporting regulation development, control strategy development and other air pollution control activities, having an electronic database populated with performance test data should save industry, state, local, tribal agencies and the EPA significant time, money and effort, while also improving the quality of emission inventories and, as a result, air quality regulations.

V. Significant Public Comments and Rationale for Changes to the Proposed Rule

This section contains a summary of major comments and responses, and rationale for changes made to the proposed rule. The EPA received many comments covering numerous topics. The EPA's responses to those comments can be found either in this preamble or in the *National Emission Standards for Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production: Summary of Public Comments and Responses*, in the PVC docket (EPA–HQ–OAR–2002–0037).

A. Affected Sources

Comment: Two commenters requested clarification on the applicability of the EPA's definition of "new source." One commenter pointed out that if a PVC manufacturing company were planning to commence construction of a new line, based on the proposed rule, the new line would trigger "new source" requirements regardless of the magnitude of HAP emissions.

Response: We believe that we have adequately addressed the concerns raised by the commenter by the way we have revised the definition of a new affected source because the addition of a PVCPU does not necessarily trigger a new affected source. In the proposed rule, the affected source was defined as each individual PVCPU, and a new affected source was a PVCPU for which construction commenced on or after May 20, 2011, at a major or area source. The proposed rule also required that, if components of an existing affected source were replaced such that the replacement met the definition of reconstruction in 40 CFR 63.2 and the reconstruction commenced on or after May 20, 2011, then that existing source becomes a reconstructed source and is subject to the relevant standards for a new affected source.

Under the proposed rule, the affected source was each PVCPU, but a PVCPU was defined to include all equipment connected by shared piping, including equipment that is typically shared by multiple units, such as heat exchangers and wastewater treatment systems. By defining a PVCPU in this manner, according to the commenter the rule

could be interpreted to mean that a change to any existing PVCPU such that it becomes subject to new source requirements or the addition of a new PVCPU could require existing affected sources also to comply with the more stringent new source standards. For example, if the facility chose to comply with the emission limits for the new PVCPU unit using an existing control device that also controlled emissions from other existing PVCPU, then all the PVCPU routing to that control device would have to meet the new source emissions limit because there would be no way to differentiate the streams at the control device. Because it might not be technically possible for existing PVCPU to meet the new source requirements, the alternative would be to construct dedicated controls or supporting process equipment for new sources. The same situation would apply to other shared equipment, such as heat exchangers and wastewater treatment. We did not intend such a result when we proposed the definitions of affected source and new source in 40 CFR 63.11870.

In light of the comments received, we are modifying the affected source definition to avoid the unintended results identified by the commenters with regard to the requirements for new sources.

In the final rule, the existing affected source is the facility-wide collection of all PVCPU, storage vessels, surge control vessels, heat exchange systems, wastewater and process wastewater treatment systems that are associated with producing PVC. A new affected source is any one of the following situations:

- All PVCPU, storage vessels, surge control vessels, heat exchange systems, wastewater and process wastewater treatment systems that are associated with producing PVC and are constructed at a Greenfield facility after May 20, 2011; or that are located at an existing facility that did not previously produce PVC prior to the rule proposal but has undergone process changes to start producing PVC.
- Reconstructed affected source.

Notwithstanding whether other approaches have been taken in other rules, the PVC NESHAP rule applies to a narrower selection of processes than HON or the Miscellaneous Organic Chemical Manufacturing NESHAP (MON), and we concluded that the affected source and new source definitions in the final rule are reasonable for the PVC industry. These edits clarify the requirements for new and existing sources and any further changes, such as defining threshold limits, are not necessary.

B. Overlapping Rules

Comment: Commenters expressed concern about overlapping requirements between the PVC MACT and other MACT that may be applicable to PVC and EDC/VCM facilities. One commenter requested that promulgation of the PVC MACT be delayed until a consolidated rule can be issued that also addresses EDC/VCM manufacturing facilities because the application of two separate rules is confusing to the regulated community. Another commenter proposed that the EPA expressly state that PVC vent streams and the centralized thermal oxidizers and ancillary equipment in which they are controlled with EDC/VCM vent streams not be subject to the requirements of the PVC MACT as long as they are controlled by the HON or other MACT standards because the commenter asserts that the EPA has made similar accommodations to address overlapping and conflicting requirements in previous MACT rules.

Other commenters requested that the EPA provide overlap provisions for facilities that are already subject to other MACT standards. The commenters stated that affected sources currently subject to other part 63 NESHAP should have the option to choose one compliance option for the entire source rather than trying to demonstrate compliance with two separate requirements for the same equipment. One commenter pointed out that the proposed rule could cause regulatory inconsistencies because, for a PVCPU utilizing a control device system already regulated under another part 63 MACT (e.g., HON), that control device would have to meet two different standards (i.e., HON MACT and PVC MACT).

One commenter proposed that the EPA should provide an option in the final rule that would allow the owner/operator to continue to comply with the existing 40 CFR part 63, subpart FFFF, the MON MACT in lieu of the PVC MACT rule if greater than 50 percent of the heat input or the organic HAP vent flow to a "shared" emission control device are from facilities that are subject to the MON MACT.

Response: In response to several of the comments, the final rule contains two subcategories for process vents: PVC-only process vents and PVC-combined process vents. Although this rulemaking is not consolidated with a rule for EDC/VCM production in the manner suggested by the commenter, the PVC-combined process vents subcategory addresses the concerns expressed. The process vent standards in the final rule for combined streams, e.g., from PVC and EDC/VCM, are based on and are consistent with emission testing conducted by the PVC and EDC/VCM industries in response to our CAA section 114 requests of PVC, VCM and EDC facilities. Our decision to set limits for the two process vent subcategories is further discussed in section V.D of this preamble. If a PVCPU uses a control device already subject to another Part 63 MACT rule such as the HON, then the facility may meet both sets of standards as applicable to the emission point or may choose to separate the two emission streams and route them to separate control devices, each complying with applicable requirements in the respective MACT standard. For the PVC process vent, the applicable standard may change from PVC-combined to PVC-only if the result is a process vent that qualifies as PVC-only.

We disagree with the commenters that requested the final rule should clearly state the governing rule when regulations overlap. If an emission point is subject to both the PVC NESHAP and other NESHAP because emissions from two source categories are vented to the same control device, both standards apply. Multiple standards applicable to one emission point for the same pollutant are not necessarily "conflicting" or "inconsistent." In some standards, the EPA has allowed compliance with another overlapping standard where that other overlapping standard was determined to be at least as stringent. However for this rule, it would not be appropriate to state that sources automatically or optionally may comply with another NESHAP in lieu of the PVC NESHAP because the requirements of the other NESHAP may be less stringent than the PVC NESHAP, including its MACT floor-based standards. If the EPA were to allow sources to meet the requirements from overlapping, but potentially less stringent rules in lieu of the PVC standards, there is the possibility that PVC facilities would not meet the MACT floor based standards in this rule. Although we recognize that facilities may be subject to different NESHAP regulations, sources are responsible for ensuring that they comply with all applicable regulations. Many NESHAP regulations provide a wide variety of compliance options, and, as such, it would be a difficult task to identify in advance which is the most stringent requirement in each case. We also disagree with allowing PVC sources to comply with other regulations, such as the MON, instead of complying with the PVC MACT, if 50 percent of the heat input or vent flow to a control device is

from a source regulated by the other standard. Such an approach is unjustified because the emissions from the PVC process might not meet the PVC MACT limits and achieve the required HAP reductions (described in the previous paragraph).

C. Pollutants Regulated

Comment: One commenter contended that the CAA required that standards be set for individual HAP and that a 2004 District of Columbia Circuit Court decision established criteria that surrogates must meet. The commenter stated that the EPA does not acknowledge this test or provide an argument that total organic HAP satisfies the identified criteria: (1) Target HAP is "invariably" present in the surrogate pollutant, (2) methods to control or capture the surrogate pollutant "indiscriminately" control or capture the target HAP and (3) the controls for the surrogate are the "only means" by which facilities "achieve" reductions of the target HAP. Another commenter claimed that each pollutant should have emission limits and procedures that achieve reduction, instead of making vinyl chloride the surrogate. Another commenter added that the EPA's failure to set emissions standards for each HAP that PVC plants emit contravenes the CAA and that the EPA must demonstrate that total organic HAP (or total HAP as proposed for stripped resin and process wastewater) is a valid surrogate. One commenter suggested that limits for the individual most toxic and most prevalent HAP, as well as the total, should be developed. Another commenter added that the proposed rule only limited vinyl chloride in monitoring of leaks, process components and wastewater streams where there are other HAP and toxins present.

Other commenters agreed with the proposed rule that total organic HAP is the appropriate parameter for limiting organic HAP emissions and the only workable approach for developing limits that comply with the CAA. The commenters also explained that a total organic HAP limit provides the product flexibility needed by the industry's downstream customers. The commenters further submitted that setting standards for each individual organic HAP would not reflect an emission level that is achieved by the best performing facilities in the industry due to the variability in emissions across the best performing facilities, consistent with the Court's observations in the PVC MACT Case.

Response: Consistent with CAA section 112(d)(2) and (3), the EPA has set standards for all HAP emitted from the major source PVC source category. Contrary to the commenters' assertion, the EPA is not obligated to set a separate MACT standard for each and every individual HAP emitted by PVC major sources. Rather, as the Court recognized in *Mossville Envt'l Action Now* v. *Whitman,* 370 F.3d 1232, 1242 (D.C. Cir. 2004) (quoting *Nat'l Lime Ass'n* v. *EPA,* 233 F.3d at 637), the EPA has authority to use surrogates to regulate HAP "if it is reasonable to do so[.]" EPA has used surrogates, as appropriate, here and set standards for the HAP emitted from the major source PVC source category.

As discussed above, the final rule contains emission limits for vinyl chloride for process vents, stripped resin and process wastewater at PVC facilities. We have set separate limits for vinyl chloride, which is an organic HAP, because vinyl chloride is present in all emission points within the PVC source category and is already regulated at PVC facilities under the part 61 NESHAP. The final rule also contains process vent emission limits for THC, as a surrogate for organic HAP.

Further, the final rule contains process vent emission limits for CDD/CDF because unlike the vinyl chloride and other organic HAP emitted from process vents at PVC facilities, CDD/CDF are generated from combustion control of organic HAP from process vents and require separate test methods to be detected and measured. Indeed, CDD/CDF cannot be detected using the test methods available to test for other organic HAP.

Finally, the final rule contains process vent emission limits for HCl, which is an inorganic HAP that is generated from the combustion control of organic HAP from process vents. HCl is controlled in a completely different manner than organics and requires separate treatment (usually a scrubber following the thermal oxidizer). As shown below, HCl is also a surrogate for chlorine. We have limited test data indicating that chlorine may be present in emissions from process vents. The HCl standard will address such emissions, however, to the extent they exist.[1]

As noted above, we are finalizing a limit on THC as a surrogate for organic HAP emissions from process vents. THC is an appropriate surrogate, applying the 3-part "test" cited by the commenter. See *Sierra Club* v. *EPA,* 353 F.3d 976, 987 (D.C. Cir. 2004). First, the target HAP at issue here (*i.e.,* organic HAP) from PVC process vents are "invariably" present in the surrogate (THC), *i.e.,* PVC process vent emissions always contain organic HAP, and the organic HAP are comprised of hydrocarbons that will be measured as THC. Second, methods to control THC (in this case, a combination of vapor recovery, such as condensers, along with thermal oxidizers for PVC process vents) indiscriminately control the target organic HAP. Finally, the methods to control THC are the only means to achieve reductions of the target organic HAP from process vents that we have identified for this source category. We considered whether changes could be made to the VCM reaction process that is used to produce PVC and/or to the chemical inputs to the reaction process, and we concluded that such changes are not possible without fundamentally changing the PVC product being manufactured by these facilities. (See discussion below regarding variety of PVC products.) It is indisputable that the controls described above, which are necessary to meet the final emission limits, result in the removal of THC, which means organics are removed as well. Accordingly, we have met the three-part test identified by the commenter for surrogacy, as we have shown that THC is an appropriate surrogate for organic HAP from PVC process vents.

The three-part test upon which the commenter relies stems from a District of Columbia Circuit case that addressed the appropriateness of using particulate matter as a surrogate for non-mercury HAP. In a different case reviewing the PVC MACT standards issued in 2002, the District of Columbia Circuit held that the EPA has authority to use a surrogate "if it is reasonable to do so[.]" *Mossville Envt'l Action Now* v. *Whitman,* 370 F.3d 1242–43. We maintain that THC is a reasonable surrogate for organic HAP based on our determination that for PVC process vents there are always organic HAP in the THC, and PVC facilities will comply with the THC standard by using vapor recovery and thermal oxidization to reduce emissions of THC, which necessarily and indiscriminately will reduce emissions of all organic HAP. Thus, the removal of the THC will remove the organic HAP. *Mossville Envt'l Action Now* v. *EPA,* 370 F.3d 1232, 1242–43 (D.C. Cir. 2004).

Similarly, HCl is a reasonable surrogate for chlorine. Chlorine is present with the HCl, and the methods to control HCl would necessarily capture or control any chlorine that may be emitted by major PVC facilities. In addition, we are not aware of any other controls for the PVC industry that

[1] As discussed in the preamble to the proposed rule, all of the standards for process vents, stripped resin and process wastewater are in the form of concentration standards.

would achieve reductions in chlorine, other than the controls that would be required to meet the final HCl limit in this rule. For additional information on chlorine and HCl see the *Revised Baseline Emission Estimates for Major Sources in the Polyvinyl Chloride and Copolymers (PVC) Production Source Category and the Revised Costs and Emission Reductions for Major Sources in the Polyvinyl Chloride and Copolymers (PVC) Production Source Category* technical memoranda in the docket for this rule.

For stripped resin and process wastewater, the final rule includes emission limits for total non-vinyl chloride organic HAP, as opposed to THC. We were not able to establish a THC limit as a surrogate for organic HAP emissions from stripped resins and process wastewater because the data available to the agency, upon which the standards were based, were from sampling a slurry (liquid), not a gaseous stream which is necessary to collect THC data and to establish THC limits. Specifically, the data in the record were sampling data taken at the outlet of the resin strippers. The outlet of a resin stripper is the most readily available place to obtain a sample (as opposed to the resin dryer exhaust) and is appropriate given that we project that all of the HAP in the resin stripper outlet are ultimately emitted from downstream processes (*e.g.*, resin dryers). However, at the outlet of the stripper, the resin is in either a slurry (liquid) or dry (solid) form, as opposed to a gaseous stream, as is the case for process vents. There are no test methods available to determine levels of THC in a liquid or solid phase. Accordingly, we had no basis on which to set a THC limit and we, therefore, established limits for vinyl chloride and total non-vinyl chloride organic HAP from stripped resin and process wastewater.

However, the control approaches used to meet the total non-vinyl chloride organic HAP emission limits are the same as those used to reduce emissions of individual organic HAP species. Specifically, because total non-vinyl chloride organic HAP is comprised of many individual organic HAP, the reduction of total non-vinyl chloride organic HAP by means of a resin stripper (for resins) and a wastewater stripper (for wastewater) will likewise reduce the target individual non-vinyl chloride organic HAP. Further, we are aware of only one means to control organics from resins and process wastewater for this source category and that is through the use of a stripper, which indiscriminately controls all organics, and we are not aware of any other control that would indiscriminately capture all organics from resins and process wastewater. Accordingly, we believe it is reasonable to set a final limit for total non-vinyl organic HAP from resins and process wastewater.

Moreover, as some of the commenters recognized, a total non-vinyl organic HAP limit is particularly appropriate given the unique nature of this industry. We set the total non-vinyl chloride organic HAP MACT floor limit for stripped resin and process wastewater on specific information provided to the EPA from stripped resin and process wastewater sampling conducted by each company in response to our August 21, 2009, CAA section 114 survey and testing request of the PVC industry. In evaluating approaches to setting standards based on the stripped resin and process wastewater data, the EPA received uncontroverted information that a PVC facility can and often does produce many different grades [2] of PVC resin, each having different characteristics based on a different chemical formulation and production recipes and consequently different organic HAP emission profiles, and that different grades can be produced on a daily basis. PVC facilities produce a particular grade of resin according to the needs of their customers and their own business decisions, and based on information provided to the EPA by industry, we conclude that the organic HAP emitted necessarily varies depending on the particular grade of resin produced. In fact, according to one commenter, a particular facility may produce up to a 100 grades of different resins, sometimes producing different resins within a single 24-hour period. Given the large number of resins that may be produced by a particular facility, the associated diversity of chemical formulations and production recipes for these different resin grades, and the resulting differences in organic HAP emission profiles coupled with the fact that the control approaches used to meet the total non-vinyl chloride organic HAP emission limits are the same as those used to reduce emissions of individual organic HAP species and are the only means of achieving such reductions, we are finalizing total non-vinyl chloride organic HAP standards for stripped resin and process wastewater at PVC production facilities. These standards together with standards for vinyl chloride directly limit all organic HAP from PVC stripped resin and process wastewater at PVC production facilities, as reported in test/sampling data available to the EPA.

In response to comments, we created five subcategories in the final rule for stripped resins. If, as some of the commenters suggest, we were to set individual organic HAP limits, industry would likely argue that we would have to consider setting standards for a prohibitively large number of subcategories, perhaps as many as there are grades of PVC resin, to ensure that facilities producing grades of PVC resin with incompatible reaction processes and/or chemical inputs were not grouped in an inappropriate manner. In the final rule, we established the additional subcategories in response to comments where we found data in the record to support such subcategorization. Without extensive additional data from industry detailing each of the resin grades they produce, by facility, with attendant emissions information, we are not in a position to evaluate whether additional subcategories are appropriate. As such, we have no basis to establish additional subcategories on this record.

As explained previously, we are establishing THC as a surrogate for controlling all organic HAP other than vinyl chloride and CDD/CDF from process vents. However, as a compliance alternative in the final rule, facilities may comply with an equivalent total organic HAP emission limit in lieu of the THC limit for process vents. Such an alternative is appropriate for process vents for the same reasons that total non-vinyl chloride organic HAP limits are appropriate for stripped resins and process wastewater, as discussed above. (See preamble section III.C for further discussion on the emission limits we are establishing.) We also note that the approach of setting total organic HAP limits for process vents (or total non-vinyl chloride organic HAP limits for stripped resins and process wastewater) is consistent with the approach in other NESHAP, such as 40 CFR part 63, subpart FFFF (the MON), which has been successful in limiting, not only total organic HAP, but also individual organic HAP.

Finally, one commenter incorrectly states that the EPA set only vinyl chloride limits for monitoring of leaks, process components and wastewater streams. As explained above, the EPA set limits for pollutants, including but not limited to vinyl chloride, emitted from process vents, stripped resins and process wastewater. The commenter incorrectly states that the equipment leak and heat exchanger standards have only a vinyl chloride limit. In the final

[2] "Grade" of PVC resin is more specific than "type" of PVC resin. See definitions in 40 CFR part 63, subpart HHHHHHH.

rule, applicability of the equipment leak work practice standards is determined based on whether the equipment is in HAP service. In HAP service means that a process component (including equipment) either contains or contacts a liquid that is at least 5-percent HAP by weight or a gas that is at least 5 percent by volume HAP. Additionally, all equipment leak standards are based on determining VOC leaks from equipment using EPA's Method 21 and fixing leaks that are detected. VOC are present throughout the PVC process. As such, if you identify a leak of VOC, fixing that leak necessarily will eliminate the VOC emissions and any other HAP emissions. Thus, VOC is a marker that is indisputably present in all PVC streams. A HAP-specific equipment leak definition is not possible because EPA Method 21, which is the only currently approved EPA method to detect equipment leaks, detects VOC, not individual compounds.

For heat exchange systems, based on comments received, we are including in the final rule a vinyl chloride leak action level and monitoring requirements because vinyl chloride is always present along with other HAP when process material leaks into cooling water, and, therefore, detection of vinyl chloride and repair of the leak will control the leak for all HAP. However, because some facilities already have programs in place to detect total strippable VOC in cooling water, we are also providing that as an option for detecting leaks into cooling water. Here, the same principle applies in that, controlling the VOC leak will in turn control HAP that leak into the cooling water. Thus, irrespective of whether a source monitors for VOC or vinyl chloride, the result is the same: Controlling any such identified leak will, in turn control any HAP that leak into the cooling water.

Finally, with respect to the commenter that suggested that limits for the individual most toxic and most prevalent HAP should be developed, the commenter fails to recognize that EPA has authority to use surrogates to address HAP. The EPA has appropriately identified the HAP emitted from the PVC source category and set standards for those HAP, including using surrogates where appropriate.

Comment: Several commenters raised issues with the term "HAP" and related terms, such as "total organic HAP" and "total HAP." Two commenters stated that, though the EPA refers to sampling and specific limits for HAP and organic HAP, there is no definition of HAP, organic HAP, or total organic HAP provided for process vents, stripped resin or other emission sources. Two commenters stated that these subsets of HAP should be restricted and defined because the PVC manufacturing process does not have the potential to emit the entire list of HAP designated by the CAA. Another commenter requested that a subset of the complete list of total organic HAP be defined specifically for suspension type process facilities. Two commenters submitted a subset of the complete list of organic HAP that they believe is appropriate to define in the rule. The commenters submitted 19 HAP that should be subjected to a stripped resin limitation through the total organic HAP approach and 11 additional HAP that were not detected, but were analyzed and reported as non-detect.

Response: The term "hazardous air pollutant" (HAP) is defined in 40 CFR 63.2 as "any air pollutant listed in or pursuant to section 112(b) of the Act". It follows directly that "total non-vinyl chloride organic HAP" means all organic HAP except vinyl chloride. The terms "organic HAP" and "total organic HAP" are commonly understood terms meaning HAP that are carbon based, individually or in total, respectively.

In the proposed rule, we did not limit the definition of total organic HAP for process vents to a specific set of organic HAP or total HAP for stripped resins and wastewater to a specific set of total HAP that are emitted by the PVC industry. Part of our intent through the issuance of the required process vent testing and resin sampling under our CAA section 114 authority was to obtain data on which HAP were in fact used, produced, and/or emitted from PVC production facilities. We have considered the commenters' suggestions on requiring compliance based on a subset of HAP, *i.e.*, those HAP that have the potential to be emitted from PVC facilities. Based on our analysis of the process vent testing data, resin sampling data, and responses to our August 21, 2009, CAA section 114 survey and testing request, we recognize that the industry does not emit all HAP, but rather only a subset of HAP, primarily organic HAP, as discussed above. We reviewed the commenters' lists of HAP for stripped resin and compared those lists to the sampling data submitted. We confirmed that PVC stripped resin and process wastewater has been shown to contain or may contain 30 of the HAP listed under section 112(b) of the CAA, in addition to vinyl chloride, and so we are requiring facilities to analyze, at a minimum, those 30 organic HAP and vinyl chloride, in both stripped resins and process wastewater samples. Although these 30 HAP are all the organic HAP we identified in the data available to the EPA, it is not appropriate to set individual HAP limits because the combination and quantity of each of these 30 HAP vary depending on the wide variety of resin grades produced within the PVC industry. As discussed previously, it would be impractical to set individual HAP limits specific to the potential large number of subcategories that would be necessary to account for the more than 100 different resin grades produced.

We are also requiring facilities to develop a facility-specific list of HAP for both stripped resins and process wastewater. The facility-specific list of HAP must include all HAP expected to be present in stripped resin and process wastewater samples, including any HAP not listed in table 10 of the final rule. Our analysis is documented in the memorandum, *Analysis of HAP in Stripped Resins and Wastewater for the Final PVC Rule.* Under this final rule, to meet the stripped resin and process wastewater total non-vinyl chloride organic HAP emission limits, you must test for those 30 HAP that are known to possibly be present in the PVC production process based on all the data available to the EPA, and, in addition, sources must test for HAP beyond those 30 that facilities are aware of based on the resin grades they produce. We are including those compounds to ensure that they would be included in the facility's calculation of total non-vinyl chloride organic HAP should those compounds become present in the process in detectable quantities.

For process vents, demonstrating compliance with the THC limit does not require testing based on a list of specific HAP as EPA Method 25A measures THC and not speciated HAP.

D. Subcategories

Comment: Two commenters contended that the EPA should use data from stand-alone PVC facilities to establish the process vent emission limits. Another commenter asserted that the agency recognized that it was important to set standards based on PVC-only vent gas flows and required industry to isolate and burn PVC-only vent streams at co-located facilities. The commenter added that thermal oxidizers at stand-alone EDC/VCM plants or co-located with PVC plants tend to be much larger than those at stand-alone PVC units. The commenter stated that to produce data in response to the CAA section 114 testing required for PVC facilities, large volumes of natural gas were burned to treat the small PVC-only vent streams to make up for the other

streams, such as EDC or VCM, that had been tied off as instructed by the CAA section 114 survey, resulting in a non-representative emission profile. The commenter noted that the Vinyl Institute Working Group submitted to the EPA a list of facilities (stand-alone PVC plants) that it believes is appropriate to use in setting the MACT floor for process vents.

Response: This final rule contains two subcategories for process vents: PVC-only process vents and PVC-combined process vents. In response to comments submitted by the industry and others, based on our review of those comments and a subsequent review of the testing data submitted in response to our August 21, 2009, CAA section 114 survey and testing request for the PVC industry, we determined that there are significant differences in the size and type of process vents that originate from PVCPU and process vents from PVCPU that are combined with process vents from other source categories, such as EDC/VCM or other HON sources, prior to control. The differences in the HAP concentrations in the process vent streams arise from the fundamental differences in the products, unit operations, and the manufacturing process of the source categories that are typically co-located with and/or that share a control device with a PVC affected source. Examples include EDC and VCM manufacturing processes, which are commonly co-located with a PVC production process and manufacture the primary raw materials (EDC is used to produce VCM) used in the production of PVC resin. Additionally, the average control device volumetric outlet flow rate is 2,100 percent greater for process vents from PVCPU that are combined with process vents from other source categories compared to process vents that originate only from PVCPU, a significant difference in size. Therefore, in the final rule, we have established two subcategories for process vents: PVC-only and PVC-combined. PVC-only process vents comprise process vent streams that originate solely from a PVC affected source. We agree with commenters who suggested that the testing conducted using large volumes of natural gas to treat these small PVC-only vent streams did not produce a representative emission profile. Therefore, we did not include those tests results to determine the PVC-only MACT floors for process vents. PVC-combined process vents comprise process vent streams that originate from a PVCPU and that are combined or are co-controlled with process vent streams that originate from other source categories, such as EDC or VCM production processes. Details on the determination of MACT floors and limits for process vents are documented in the technical memorandum, *Revised Maximum Achievable Control Technology (MACT) Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* which is available in the docket.

Comment: Two commenters contended that PolyOne's vent gas absorbers are recovery devices and not control devices because they capture and recycle vinyl chloride back into the production process, rather than treating it as a waste. The commenters added that, because PolyOne's vent gas absorbers do not operate at elevated temperatures or combust the vinyl chloride, they do not result in the formation of additional HAP or generation of unwanted by-products, such as CDD/CDF and greenhouse gases. The commenters contended that the proposed MACT would require backup thermal oxidizers to be used continuously. The commenter added that large amounts of energy will be consumed and greenhouse gasses emitted in an effort to control a tiny amount of VOC. The commenter concluded by arguing that consideration should be given to the overall air impact of operating backup thermal oxidizers continuously.

Another commenter stated that the flow rate out of PolyOne's absorbers is two orders of magnitude less than the emissions flow rate from control device technology that includes thermal oxidizers and scrubbers combined. The commenters stated that the proposed MACT should take emissions rates into consideration and not solely rely on emissions concentrations when establishing limits for recovery devices. One commenter added that for sites equipped with vent gas absorber recovery technology, thermal oxidizers are necessary only in the event of an outage or malfunction with the operation of the vent gas absorbers to ensure that any vinyl chloride, which is not recycled back to the process, is destroyed.

Response: The rule contains emission limits for process vents that apply at the point where the gaseous stream is released to the atmosphere. While we recognize that a vent gas absorber at the commenter's facilities recover vinyl chloride, those absorbers also have stacks that emit to the atmosphere and would therefore be subject to the process vent limit. The rule does not require that affected sources use a specific control or recovery device to meet the process vent limits, and the final emission standards are not based on whether a vent gas absorber is classified as a recovery device or control device. An affected source may use any control device to reduce the process vent emissions to meet the required limits. We considered setting alternative formats for the process vent emission limits. However, we did not have sufficient information provided from industry on process vent stream flow rates and concentrations to develop or evaluate other formats, such as mass emission rates.

Comment: Many commenters contended that the EPA should further subcategorize resins. One commenter stated that the EPA should recognize that resin recipes, production processes and equipment required for end product utility, govern the emissions and the ability to strip each type of resin. The commenter stated that the data provided by the Vinyl Institute demonstrate the differences between production processes and PVC morphology and particle size of the PVC products manufactured. The commenter added that these differences equate to differences in ability to steam strip the resin of vinyl chloride, among other things.

Several commenters stated that copolymer resins are a completely different chemistry from homopolymer resins and should be regulated through their own subcategory. The commenters requested that the EPA subcategorize stripped resin by differences in chemistry (co-monomers), raw material inputs, process equipment, resin types and grades or other factors, provided such subcategorization is reasonable.

One commenter objected to the agency's proposal to subcategorize resins as "bulk" and "dispersion," with all other resins, including copolymers, suspension blending and suspension resins relegated to an "other resin" subcategory. The commenter stated that the EPA's proposed subcategorization scheme is textually inconsistent and will likely cause regulatory confusion within the industry. The commenter stated the agency's proposed subcategories ignore critical differences in processing equipment, material inputs and resin morphology that have a critical and differentiating impact on the HAP profile of the various resins. The commenter contended that, at a minimum, the EPA should organize stripped resin limits along the following subcategories for homopolymers: Suspension, dispersion, bulk and blending; and for copolymers: Suspension, dispersion, blending and solution. The commenter added that by

definition, "copolymers" were considered distinct enough from polyvinyl chloride polymers that the EPA used the conjunctive "and copolymers" to describe the source category being addressed here.

One commenter added that the EPA should subcategorize copolymers by the resin type because they are capable of being manufactured in different processes (suspension, dispersion and solution) that present completely different HAP emission profiles. The commenter stated that the general class of copolymers requires differentiation from the homopolymer category. The commenter added that within this copolymer class there are different resin types (suspension, dispersion, blending and solution) that require subcategorization similar to homopolymers. The commenter continued that for each resin type, however, the choice of co-monomer creates different HAP profiles affecting the HAP analyzed; co-monomers are chosen, based on the end product characteristics specified by the customer. The commenter added that the vinylidene chloride copolymer is a highly crystalline polymer, making the removal or stripping of vinyl chloride from the resin more difficult than typical PVC polymers. The commenter stated that, to require its facility to meet this proposed standard for all other resins, is technically infeasible, based on the unique chemistry used.

Several commenters contended that dispersion resins should be regulated separately from suspension blending resins. The commenters stated that dispersion resins and suspension blending resins should be included in the MACT as their own categories due to the very different nature of both the manufacturing technologies used and the resins produced. The commenter added that suspension blending resins are a type of specialty resin used in flooring, automotive interiors and synthetic leather products. The commenters stated that the proposed MACT does not specifically address suspension blending resins, leaving this class of resin manufacturing unclear. Further, for the same reasons discussed for dispersion resins, the commenters contended that suspension blending resins require a separate subcategory under the proposed MACT. The commenters asserted that suspension blending resins have very different characteristics than generic suspension resins, including smooth surfaces and different particle sizes of distribution, all of which present different challenges when stripping vinyl chloride from a different resin.

One commenter added that the previous 30-day data submitted pursuant to the EPA's CAA section 114 request for PVC facilities were not representative of blending PVC resin alone. The commenter stated that the data were for suspension, including suspension blending PVC resin. The commenter asserted that samples for regular suspension resin were composited with blending PVC resin samples to get one daily suspension analysis rather than analyzing the samples separately. The commenter stated that both categories react to steam stripping quite differently and truly are different products. One commenter submitted data to support their assertion that suspension blending PVC resin, because of its unique morphology, could not possibly be stripped to the levels proposed for suspension general purpose resin. Two commenters argued that further subcategories of suspension resins should either be established or considered. One commenter requested that the EPA subcategorize the emission limits for the "other resin" category into the following subcategories: Low molecular weight (LMW), high molecular weight (HMW) and general purpose.

Response: In the proposed rule, limits were developed for new and existing sources for three subcategories of PVC resin: (1) Bulk resin, (2) dispersion resin and (3) all other resins. Based on our review of the public comments and our concurrent review and analysis of the additional data on the vinyl chloride concentrations in stripped resins submitted by the PVC industry, we determined that the data clearly show that there are significant differences in the concentrations of vinyl chloride and other HAP that remain in the various types of resins following stripping. The differences in the concentrations of vinyl chloride and other HAP that remain in the various resin types are a direct consequence of several factors related to the overall process to produce each resin type. These factors include: The different raw materials necessary to produce each resin type, the unique process chemistry required to produce each resin type, the process conditions required to produce each resin type and differences in the morphology of the resin particles following polymerization. The current technology that is used to remove residual vinyl chloride and HAP from polymerized resin is steam stripping. The conditions under which steam stripping is performed are unique to the resin type being produced and the ability to strip, or remove the maximum amount of residual vinyl chloride and HAP from the resin types, is constrained by the resin morphology, product quality and customer end-use requirements. The different resin types all differ in morphology, particle size and porosity, which all affect the ability to remove residual, or unreacted VCM and other HAP from the resin matrix. For a steam stripping unit that is operating as designed to remove the maximum amount of residual vinyl chloride and HAP from polymerized resin, simply adding more steam to that unit may result in some additional removal of vinyl chloride and other HAP, but the additional heat from the steam will degrade the resin and thus negatively affect the resin quality such that it will not meet customer or performance specifications. Therefore, for the final rule, we are responding to the comments and information submitted to the EPA by dividing the limits for stripped resins into two general groupings: (1) Homopolymers and (2) copolymers. Homopolymer resins are further divided into four subcategories: (1) Suspension resin, (2) dispersion resin, (3) suspension blending resin and (4) bulk resin. Some commenters suggested further subcategorizing copolymer resins; however, the data submitted by industry to the EPA did not include sufficient specificity that would allow developing additional subcategories of copolymer resin types. Therefore, copolymer resins are not further subcategorized in the final rule. Other commenters suggested additional subcategories based on molecular weight, grade and other physical properties. However, we did not develop additional subcategories for various resin grades (e.g., LMW, HMW or general purpose) because this could have potentially resulted in hundreds or thousands of resin subcategories, each with its own MACT analysis, making such an approach impractical to establish and administer.

E. MACT Floor Calculation

Following proposal, industry submitted additional data and information on several emission sources: (1) Process vents, (2) stripped resins, (3) process wastewater and (4) gasholders. For process vents, stripped resins and process wastewater, we received additional data for organic compounds and HCl. Metal HAP are not present in the PVC production process. The post-proposal data submittals are available in the docket. The data were used to revise the MACT floors and impacts.

1. Additional Data Submitted Process Vents

Industry provided data clarifying which PVC facilities are co-located with EDC and VCM production or other source categories and which facilities are stand-alone PVC producers. Industry also provided clarification of the conditions (e.g., percentage contribution of the PVCPU to the total process vent stream) during stack testing conducted in response to our August 21, 2009, CAA section 114 survey and testing request sent to PVC companies. Industry identified which facilities typically co-control non-PVC streams. The EPA also received results of emissions tests conducted for EDC and VCM production facilities, some of which are co-located and co-controlled with PVC production facilities, as required by our March 16, 2011, CAA section 114 survey and testing request for VCM/EDC production companies. The CAA section 114 request required that emission data be collected by testing the VCM/EDC process vents for vinyl chloride, dioxin/furan and THC emissions. The results of emissions tests from the co-located and co-controlled facilities included data for PVC-combined process vents (e.g., any VCM/EDC process vent that also contains a PVC process stream) that were included in the MACT floor analysis for PVC-combined process vents.

Stripped Resin

Industry provided a database containing 4 years of daily average vinyl chloride concentrations in stripped resins, determined by using EPA Method 107 for all but two PVC production facilities. The provided database contained information for four specific resin types: (1) Suspension, (2) dispersion, (3) suspension blending and (4) vinyl acetate copolymer (VACO).

Industry also submitted an updated 30-day resin sampling concentration database for total HAP, based on using various EPA SW–846 Methods and providing additional specificity on resin types and corrections to previously submitted data; VACO and suspension blending data were separated from dispersion and suspension data, respectively. Another commenter submitted new vinyl chloride and total organic HAP data for suspension blending resin as a result of additional sampling and testing performed by the company independent of the EPA's CAA section 114 request for the PVC production industry.

Additionally, results that were reported as composites of two or more resin types were identified by resin type, and previous results from the OxyVinyls suspension plants that were indicated as a reporting limit (RL) were changed to non-detect. Vinylidene/vinyl chloride copolymer concentration data from Dow Chemical were also added to the database.

Wastewater

Commenters submitted approximately 1 year of vinyl chloride concentration data at the outlet of wastewater strippers for nine PVC production facilities. All concentrations were obtained using EPA Method 107. The data were provided on a varying basis across facilities (e.g., daily, weekly, monthly).

Gasholders

In response to industry comments, we requested and received annual emissions estimates for small and large sized gasholders. In addition to submitting comments regarding suggested control and work practice options for gasholders, industry also provided estimates of the capital cost and emission reductions for work practices that could be used to reduce emissions from gasholders, i.e., using floating objects.

Equipment Leaks

At proposal, we ranked the LDAR programs used at each affected PVC source from most stringent to least stringent, based on the leak definitions, monitoring frequencies, control requirements and repair requirements reported in the responses to our August 21, 2009, CAA section 114 survey and testing request. We then identified the LDAR programs employed by the best-performing five sources. The results of this analysis showed that three out of the best-performing five sources comply with 40 CFR part 63, subpart UU level 2 controls. Therefore, we proposed that existing and new affected sources comply with the LDAR program requirements of the National Emission Standards for Equipment Leaks-Control Level 2 Standards, subpart UU of 40 CFR part 63.

During the comment period, one of the facilities that had responded that they complied with subpart UU of 40 CFR part 63 (Shintech Freeport), stated that the survey response was in error, and the facility is actually complying with the equipment leak requirements of 40 CFR part 61, subpart V. This change results in a revision to the MACT floor for existing major sources, which is discussed in section V.E.2 of this preamble.

2. MACT Floor Revisions

In the final rule, we revised the MACT floor-based emission limits for process vents, stripped resins and wastewater, as discussed in the technical memorandum, *Revised Maximum Achievable Control Technology (MACT) Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* which is available in the docket.

Process Vents

In the final rule we calculated the MACT floors for the two process vent subcategories, PVC-only and PVC-combined, accounting for variability using the UPL calculation. At proposal, a 99-percent UPL calculation was used where the m value (representing the number of test runs used in the compliance average) was 30 for the THC compliance limit option. For the final rule, we changed the m value to 3 because 3 THC test runs using EPA Method 25A will be performed over the 5-year period with which compliance will be averaged. Therefore, an m value of 3 for the THC UPL calculation is appropriate.

In the final rule, we revised the procedure for identifying a representative method detection level (RDL) for vinyl chloride, HCl, CDD/CDF, THC and total organic HAP for PVC-only and PVC-combined process vents. At proposal, we determined the RDL by identifying the highest test-specific MDL reported by the top 5 best-performing facilities for each pollutant in each subcategory that was also less than the calculated average emission concentration of those top 5 best-performing facilities.

For the final rule, the RDL for vinyl chloride and total organic HAP was determined by identifying the available reported pollutant-specific MDL values for the top 5 best-performing units regardless of any subcategory. However, the data set of reported pollutant-specific MDL values included MDL values only from reference methods for new source performance standards (NSPS) and NESHAP rulemakings since they are the established compliance methods for air pollutants and have a more robust quality assurance procedure. For our August 21, 2009, CAA section 114 testing request, other test methods besides reference methods for NSPS/NESHAP (i.e., EPA SW–846 Method 0031) were used to account for all the possible HAP that could potentially be emitted from process vents. Emission data collected as a result of performance testing with non-reference methods for NSPS/NESHAP

were used in the MACT floor analyses since the resulting values could be measured using reference methods. From that combined pool of MDL data, we calculated the arithmetic mean value. We then called the resulting mean of the MDL values the RDL.

For HCl and CDD/CDF we used RDL values based on data collected for several hundred EPA Method 23 and EPA Method 26A emissions tests from various industries, a much larger data set than the one compiled only from PVCPU testing. The RDL values calculated from the larger data sets are more representative of the inherent measurement variability both within and between testing companies. The RDL values were determined by the same procedure described above for vinyl chloride and total organic HAP. All of the available reported pollutant-specific MDL values for the best-performing facilities regardless of any subcategory were identified and an arithmetic mean was calculated from the resulting data set and determined to be the RDL.

For THC, we determined that the RDL for EPA Method 25A for a 10-ppm propane span would be 0.5 ppm propane. We arrived at this RDL by surveying the typical flame ionization analyzers in use by the testing community and evaluating the required method criteria in EPA Method 25A. The survey of the instruments yielded several vender stated instrument detection limits from 0.01 to 0.5 ppm as carbon with one independent third party degermation of 0.8 ppm as carbon. In addition, several instruments' minimum reportable resolution is 0.1 ppm as propane. The method criteria allows for a 3-percent zero and span drift during performance runs and an initial criteria of 5 percent of the calibration gas. The sum allowable calibration error and drift would be approximately 0.475 ppm as propane (using a 3.5-ppm propane span gas), which would be higher than the instrumental detection limits.

For vinyl chloride, HCl, CDD/CDF, THC and total organic HAP, the MACT floor emission limit was compared to 3 times the RDL. As in the proposed rule, if 3 times the RDL was greater than the calculated MACT floor emission limit, we concluded that the MACT floor emission limit does not account entirely for measurement variability and, therefore, we used the value equal to 3 times the RDL in place of the calculated MACT floor emission limit. The variability analysis conducted for the final rule is contained in the memorandum titled *Revised Maximum Achievable Control Technology (MACT) Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category*, and is available in the docket.

Stripped Resin

Vinyl chloride and total HAP limits for stripped resins were calculated at proposal using a 99-percent UPL calculation and 30 days of vinyl chloride and other HAP data from all facilities that conducted resin sampling and analysis as part of our August 21, 2009, CAA section 114 survey and testing request for the PVC industry. In developing the proposal, we requested sources subject to the CAA section 114 request provide information on the residual compounds in the resin leaving the stripper on a mass-basis. After the mass-based sampling results were submitted to us, the Vinyl Institute, on behalf of the PVC industry, provided a database of the concentration values that were used by the facilities to convert their concentrations to mass-based values. For the proposed rule, we calculated limits for dispersion resin, based on the reported mass-based values for each HAP present in the resin, which we then converted to concentrations, based on dispersion resin production. The proposed limits for all other resin types (i.e., suspension resin) were calculated, based on the originally measured vinyl chloride concentration values that were reported by each suspension resin facility and compiled into the concentration database that was supplied to us by the Vinyl Institute. The limit for bulk resin was calculated using the vinyl chloride and other HAP concentrations provided by the single bulk resin manufacturing facility in their response to the CAA section 114 request for the PVC industry. Variability was not assessed in the calculation of the limit for bulk resin because the data for vinyl chloride and total organic HAP consisted of one unique value each.

We received numerous comments on our approach at proposal for calculating stripped resin limits, which included comments on the subcategories, the use of mass-based values for determining the limits for dispersion resin, the use of vinyl chloride concentration data collected via EPA Method 107 in calculating a total organic HAP limit where a different test method was used for other non-vinyl organic chloride HAP, our approach for accounting for variability in the stripped resin limits and the m value in the UPL calculation for both vinyl chloride and total organic HAP.

During the public comment period, the Vinyl Institute provided us with an updated database, as described above, of the vinyl chloride and other HAP concentration values that were measured as the resin was exiting the stripper(s) and that were not then converted by the facilities to mass values. We also received supplemental resin sampling data from one PVC facility (PolyOne) and further information regarding their previous data submittals. In consideration of the comments received and our subsequent review and analysis of the submitted data, we made several changes to the limits for stripped resins. No additional data were provided from the single bulk resin manufacturer, so the final limits for bulk resin were recalculated only to remove vinyl chloride from the calculation for the total non-vinyl chloride organic HAP limit. Variability was not assessed in the calculation of the limit for bulk resin because the data for vinyl chloride and total HAP consisted of one unique value each. For the final rule, we used the original concentration values, as measured during the required emission testing of our August 21, 2009, CAA section 114 survey and testing request, and analyzed it as the basis for setting the MACT floors for suspension, dispersion, suspension blending and copolymer resin. This provided a consistent basis to compare concentrations of vinyl chloride and other HAP and calculate limits on a consistent basis. At proposal, the vinyl chloride limits for all subcategories except for bulk resin were calculated using data obtained from EPA SW–846 Method 8260B and a representative detection limit analysis was performed, based on those data. For the final rule, vinyl chloride limits were determined by using a percentile calculated from 4 years of vinyl chloride concentration data from the top five sources that were obtained by sampling using EPA Method 107 and provided by the Vinyl Institute. The change in methodology was appropriate because the 4-year data set was sufficiently large (between 523 and 5,165 data points total for the calculation of each limit, depending on the resin subcategory, and not including bulk resin) that it is not necessary to estimate variability by use of the UPL equation. Rather, by using a percentile, variability is accounted for directly from the vinyl chloride data set comprised of the lowest emitting sources. Percentiles represent the specified slice of the sample data and unlike confidence and prediction intervals, they are distribution-free. Furthermore, the overwhelming majority of vinyl chloride concentration values reported were above the

detection limit for EPA Method 107 and therefore, a representative detection limit analysis did not need to be performed.

In the proposed rule, the total HAP limits for the stripped resin subcategories included the contribution from vinyl chloride. In the final rule, vinyl chloride concentrations were removed from the total HAP limit calculations, resulting in limits for total non-vinyl chloride organic HAP for all subcategories of stripped resin. This was appropriate because the data used to develop the MACT floors and limits for vinyl chloride in stripped resin were based on EPA Method 107. While vinyl chloride can be analyzed using EPA SW–846 Method 8260B, a total HAP limit that includes vinyl chloride analyzed using that method would be inconsistent with our separate limit for vinyl chloride alone, which is based on data obtained using EPA Method 107. Since we have developed a separate vinyl chloride limit, it is not necessary to include vinyl chloride as part of the total HAP limit for stripped resins. Because different test methods were used to develop the emission standards, we are requiring compliance testing and sampling based on the different test methods to demonstrate compliance with those standards. The differences in the test methods (e.g., the way that samples are collected and analyzed) caused the vinyl chloride emissions to differ by orders of magnitude when the same sample was tested using the two different methods. At proposal, variability was assessed for total HAP using a 99-percent UPL calculation with the m value set at 30 to represent 30 single daily total HAP values. For the final rule, variability was assessed for total non-vinyl chloride organic HAP using the 99-percent UPL calculation; however, because we are requiring compliance with the total non-vinyl chloride organic HAP limits for all subcategories to be based on a single 24-hour period taken once per month, we calculated the UPL for total non-vinyl chloride organic HAP using an m value of 1.

For the final rule, we revised the procedure for identifying an RDL for total non-vinyl chloride organic HAP. At proposal, we determined the RDL by identifying the highest test-specific MDL reported by the top 5 best-performing facilities for total HAP in each subcategory that was also less than the calculated average concentration of those top 5 best-performing facilities. For the final rule, the RDL for total non-vinyl chloride organic HAP was determined by identifying all of the available MDL values for the top 5 best-performing facilities regardless of any subcategory. From that combined pool of MDL data, we calculated the arithmetic mean value. We then called the resulting mean of the MDL values the RDL. As in the proposed rule, if 3 times the RDL was greater than the calculated limit, we concluded that the MACT floor limit does not account entirely for measurement variability and, therefore, we used the value equal to 3 times the RDL in place of the calculated MACT floor limit.

For the final rule, we excluded: (1) Copolymer resin data from Dow Chemical's Midland, Michigan, facility due to the lack of a sampling and analysis report documenting the analysis results, (2) data from Georgia Gulf's Aberdeen, Mississippi, and Plaquemine, Louisiana, facilities because the data reported from analysis using a modification to EPA SW–846 Method 8260B could not be compared to data reported from other PVC facilities that analyzed resin concentrations using an unmodified EPA SW–846 Method 8260B and (3) selected reported HAP concentrations from PolyOne's Henry, Illinois, facility due to unexpectedly high reported detection limits that we determined were inaccurate when compared to the reported detection limits from other facilities.

Wastewater

For the proposed rule, the wastewater vinyl chloride concentration limits were calculated using a 99-percent UPL calculation with an m value of 1 to represent monthly compliance, based on a single sampling event. The limits were calculated, based on data provided by facilities in their CAA section 114 survey responses. These data represented a mix of sampling data, engineering estimates and mass balance calculations. Post proposal, industry submitted 1 year's worth of vinyl chloride sampling data results from wastewater strippers at several facilities. For the final rule, we recalculated the monthly vinyl chloride concentration limits using a 99-percent UPL calculation, as described above, but the limits were calculated based on the actual vinyl chloride sampling data provided by the industry.

We used the UPL to assess variability in the calculation of the final limits for process wastewater. Despite the substantially larger vinyl chloride concentration data set provided by the industry during the public comment period, the percentile approach was not used as it was for the stripped resin vinyl chloride limits because the final data set was not sufficiently large (60 data points total, or 12 monthly vinyl chloride values for each of the top five performing facilities) and we had to make assumptions about the distribution of the data.

In the proposed rule, total HAP emission limits were based on a beyond-the-floor option of complying with the HON flow rate and concentration values. For the final rule, we calculated a total non-vinyl chloride organic HAP emission level at the MACT floor, based on non-vinyl chloride organic HAP data reported by PVC facilities and using the same calculation methodology used to determine the MACT floor vinyl chloride emission limit with compliance demonstrated on a monthly basis. In the proposed rule, the total HAP limit for wastewater included the contribution from vinyl chloride. In the final rule vinyl chloride concentrations were removed from the total non-vinyl chloride organic HAP limit calculation, resulting in total non-vinyl chloride organic HAP limits for process wastewater. This approach was appropriate since we are requiring different test methods to demonstrate compliance with the vinyl chloride and the total non-vinyl chloride organic HAP limits.

The determination of the RDL value for vinyl chloride was revised for the final rule as previously described for process vents. Industry did not provide non-detect data for total non-vinyl chloride organic HAP; therefore, non-detect data were not incorporated in the total non-vinyl chloride organic HAP limit calculation.

Equipment Leaks

Based on changes to information reported by Shintech Freeport, as discussed above, we revised the MACT floor analysis for equipment leaks at existing sources. The results of this analysis showed that two out of the best-performing five sources comply with 40 CFR part 63, subpart UU level 2 requirements, and the remaining three complied with 40 CFR part 61, subpart V. For the final rule, the MACT floor level of control for equipment leaks at existing sources, taking the median of the best-controlled five sources, is compliance with subpart V.

Comment: One commenter stated that in the proposed PVC MACT, new source emission limits for process vents, the resin stripper and wastewater were based on the best-performing emission source. However, the commenter stated that the data sets used to establish the new source MACT floor were not adequate or representative of the best performance from the source.

The commenter added that the new source process vent MACT floor was established by selecting the best performance of each individual HAP from all facilities. The commenter asserted that, as a result, no current facility can meet the control level represented by the proposed new source MACT. The commenter requested that the EPA re-evaluate the feasibility of the new source MACT floor analysis for on-going, continuous compliance.

Response: At proposal and in this final rule, we used the data available to us to conduct the new source MACT floor analyses. A reasonable interpretation of CAA section 112(d)(3) is that MACT floors may be established on a HAP-by-HAP basis, so that there can be different pools of best performers for each HAP. Indeed, as illustrated below, the total facility approach is not only not compelled by the statutory language, but can lead to results so arbitrary that the approach may simply not be legally permissible.

CAA section 112(d)(3) is not explicit as to whether the MACT floor is to be based on the performance of an entire source or on the performance achieved in controlling particular HAP. Congress specified in CAA section 112(d)(3) the minimum level of emission reduction that could satisfy the requirement to adopt MACT. For new sources, this floor level is to be "the emission control that is achieved in practice by the best controlled similar source." For existing sources, the floor level is to be "the average emission limitation achieved by the best performing 12 percent of the existing sources" for categories and subcategories with 30 or more sources, or "the average emission limitation achieved by the best performing 5 sources" for categories and subcategories with fewer than 30 sources. The language of the CAA does not address whether floor levels can be established HAP-by-HAP or by any other means. The reference to "sources" does not lead to the assumption the commenters make that the best-performing sources can only be the best performing sources for the entire suite of regulated HAP. Instead, the language can be reasonably interpreted as referring to the source as a whole or to performance as to a particular HAP. Similarly, the reference in the new source MACT floor provision to "emission control achieved by the best controlled similar source" can mean emission control as to a particular HAP or emission control achieved by a source as a whole.

The EPA's long-standing interpretation of the CAA is that new source (as well as existing source) MACT floors are to be established on a pollutant-by-pollutant basis.[3] One reason for this interpretation is that a contrary approach could yield least common denominator floors—that is, floors reflecting mediocre or no control rather than what the best performers have achieved. See 76 FR at 15622, March 21, 2011; 61 FR at 173687, April 19, 1996; 62 FR at 48363–64, September 15, 1997 (same approach adopted under the very similar language of CAA section 129(a)(2)). Such an approach would allow a source that is not the best-performer for certain pollutants nonetheless to be considered the best performer overall, including for those same pollutants for which it is demonstrably not the best performer. It is even conceivable that the worst performing source for a pollutant could be considered the best performer for all pollutants, a result Congress could not have intended.

For example, if the best-performing five sources for vinyl chloride were also the worst performing sources for HCl and the best performers for HCl were the worst performers for vinyl chloride, under a total facility approach the floor would end up not reflecting best performance for HCl and vinyl chloride. In such a situation, the EPA would have to make a value judgment as to which pollutant reductions were most critical to decide which sources are best-controlled. See Petitioners Brief in *Medical Waste Institute et al.* v. *EPA*, No. 09–1297 (DC Cir.) pointing out, in this context, that "the best performers for some pollutants are the worst performers for others" (p. 34) and "[s]ome of the best performers for certain pollutants are among the worst performers for others." Such value judgments are antithetical to the direction of the statute at the MACT floor-setting stage.

The central purpose of the amended CAA section 112(d) provisions was to apply strict technology-based emission controls on HAP. See, *e.g.*, H. Rep. No. 952, 101st Cong. 2d sess. 338. An interpretation that the floor level of control must be limited by the performance of devices that only control some of these pollutants effectively guts the standards by including worse performers in the averaging process, whereas the EPA's interpretation promotes the evident Congressional objective of having the floor reflect the average performance of best-performing sources. Because Congress has not spoken to the precise question at issue, and the agency's interpretation effectuates statutory goals and policies in a reasonable manner, its interpretation must be upheld. See *Chevron* v. *NRDC*, 467 U.S. 837 (1984).

The EPA notes, however, that if optimized performance for different HAP is not technologically possible due to mutually inconsistent control technologies (for example, if HCl performance decreased as organics reduction is optimized), then this would have to be taken into account by the EPA in establishing a floor (or floors). The Senate Report indicates that if certain types of otherwise needed controls are mutually exclusive, the EPA is to optimize the part of the standard providing the most environmental protection. S. Rep. No. 228, 101st Cong. 1st sess. 168 (although, as noted, the bill accompanying this Report contained no floor provisions). It should be emphasized, however, that the District of Columbia Circuit has stated that "the fact that no plant has been shown to be able to meet all of the limitations does not demonstrate that all the limitations are not achievable." *Chemical Manufacturers Association* v. *EPA*, 885 F. 2d at 264 (upholding technology-based standards based on best performance for each pollutant by different plants, where at least one plant met each of the limitations but no single plant met all of them).

Such an approach would not meet the requirements of the CAA. For these reasons, the EPA's approach is the appropriate methodology for developing new source MACT floors and no further reevaluation is necessary.

Comment: Several commenters argued that the EPA calculated the MACT floor for vinyl chloride in stripped resin using data based on one analytical method (EPA Method 8260B) that typically underreports vinyl chloride and requires compliance with a different test method (EPA Method 107) developed specifically for vinyl chloride.

Response: We agree with the commenters that there was a tension in the proposed rule between the data used to establish the limits and the test methods required for compliance. We specifically solicited comment on this issue in the proposed rule. After consideration of information received after the proposed rule, including the potential benefits and drawbacks of both EPA SW–846 Method 8260B and EPA Method 107 in terms of vinyl chloride analysis, we conclude that EPA Method 107 is more appropriate for developing MACT floors and for determining

[3] We have done precisely that in this rule by setting emission standards for vinyl chloride, THC (or total organic HAP), total non-vinyl chlorideorganic HAP, CDD/CDF and HCl. See preamble section V.C.

compliance with such standards for vinyl chloride in stripped resins.

EPA Method 107 was specifically developed for use in the PVC industry and is the standard method for determining vinyl chloride concentrations in not only stripped resin samples, but also wastewater samples. The method provides for better extraction of the vinyl chloride and, therefore, produces more reliable and accurate, albeit nominally higher, concentration results. EPA SW–846 Method 8260B also allows for the analysis of vinyl chloride, but the method was not specifically developed for measuring vinyl chloride in PVC resin samples and so has lower reliability and accuracy compared to EPA Method 107 in this context.

Based on our analysis of data collected on vinyl chloride concentrations in stripped resin samples analyzed using both EPA Method 107 and EPA SW–846 Method 8260B, concentration values obtained using EPA Method 107 are consistently higher than the concentration values obtained on the same resin samples using EPA SW–846 Method 8260B. As such, compliance with a vinyl chloride limit based on data obtained using EPA SW–846 Method 8260B could not necessarily be determined based on compliance data obtained using EPA Method 107, making the Method 107 data inappropriate as a required basis for determining compliance with the limit based on data obtained from EPA SW–846 Method 8260B.

In the final rule, we calculated the MACT floor-based limits for vinyl chloride in stripped resins based on sampling data collected using EPA Method 107. We also require demonstration of compliance with the stripped resin vinyl chloride limits using EPA Method 107. In the final rule, we have also revised the stripped resin and wastewater limits for total organic HAP to separate vinyl chloride from those limits, resulting in total non-vinyl chloride organic HAP limits. As discussed above, EPA Method 107 is the preferred method for determining vinyl chloride concentrations in PVC stripped resin and wastewater. The EPA believes it would be inappropriate and inaccurate to determine and require compliance with total HAP standards by combining results from the two different methods because the EPA Method 107 data for vinyl chloride would be artificially overweighted compared to the data for non-vinyl chloride organic HAP based on analysis using EPA SW–846 methods, including Method 8260B, based on the significant differences in sampling results when using the methods on the same samples.

Comment: Several commenters stated that the data used to set the MACT floor are not based on normal operating conditions. One commenter stated that testing pursuant to the CAA section 114 request was conducted at the PVC production units in late 2009 and early 2010. The commenter contended that, during this period, the industry was operating by as much as 34 percent below its maximum production rates over the prior 3 years. One commenter contended that the test conditions were not representative of normal maximum operating conditions for a stand-alone PVC producer under which these values were determined and the EPA incorporated test results from much larger thermal oxidizers operated well under their maximum design operating conditions. To enable compliance with a reasonably proposed standard, the commenter stated that the EPA should revise the final rule to allow for new sources to come into compliance 3 years after the final rule is promulgated.

One commenter contended that the proposed limits for vinyl chloride, total organic HAP and HCl need to be factored-up to allow facilities to operate at maximum production rates. The commenter added that it is necessary to factor up proposed limits because the EPA's compressed schedule for gathering data did not allow facilities to test at maximum or near maximum operating rates. The commenter stated the rule, as proposed, requires facilities to perform compliance tests under hypothetical or actual worst case conditions (i.e., maximum operating rates), which is not the same conditions used to generate the data that set the standard for proposed vents. The commenter proposed, as an alternative, that industry should be allowed to test under the same conditions that were present during the stack tests conducted to comply with the CAA section 114 request.

Commenters indicated that tests done at the OxyVinyls Deer Park and Pasadena facilities and Formosa Plastics' Baton Rouge facility were conducted under abnormal operating scenarios that are not indicative of their normal operation. The commenters provided information on how the operating conditions during the test differed than at normal conditions. The commenters contended that the MACT floors should be calculated without these facilities. The commenter contended that data from that period are inappropriate for setting the MACT floor for maximum representative operating conditions. One commenter stated that during the data request for the MACT floor study, the EPA asked for data (stack testing and 30-day monitoring) related to "normal operations" in order to set up the MACT floor. However, the commenter asserted that the proposed rule set up limits for compliance (standards and operating limits) that are to be based on "maximum operations" from the subject facilities. The commenter contended that since the MACT floor data are different from what is expected from facilities for compliance with the standard, the EPA should either re-analyze the MACT floor data to revise the proposed regulatory requirements or ask the facilities for additional, and more specific, relevant data regarding maximum operating conditions. Other commenters contended that the EPA should have accounted for the testing variance that occurred by sampling and testing during a period of lower throughput for the industry. The commenters requested that the EPA adjust for lower production levels in the final rule.

Response: We agree with commenters that the OxyVinyls Deer Park and Formosa Baton Rouge facilities have PVC-combined process vents and should not be included in the PVC-only MACT floor calculation. OxyVinyls provided additional stack test information for the Deer Park facility in response to our CAA section 114 request for VCM/EDC facilities, and the OxyVinyls Deer Park facility has been included in the PVC-combined MACT floor calculation. Further discussion regarding the OxyVinyls Deer Park facility is found in response to comments below and responses regarding area sources. The Formosa Baton Rouge facility has PVC-combined process vents, not PVC-only process vents. However, they submitted test results in response to our August 21, 2009, CAA section 114 survey and testing request that were collected while the control device at the facility was controlling vent streams from the PVC process only. Therefore, the test results are not representative of a PVC-only facility due to an abnormally large amount of natural gas combusted during the time of testing to maintain operation of the thermal oxidizer. Furthermore, that facility was not included in our CAA section 114 request for VCM/EDC facilities. Therefore, we have excluded the Baton Rouge facility from any process vent MACT floor calculations. We disagree with the commenters that the OxyVinyls Pasadena facility be removed from the PVC-combined process vent MACT floor calculation due to the facility experiencing a

malfunction during process vent testing. According to the source, the specific nature of the malfunction at the OxyVinyls Pasadena facility allowed a percentage of the process vent stream to bypass the control device and enter the vent stack. As a result, both controlled and uncontrolled emissions were measured during process vent testing; however, the facility's measured concentrations were still low enough to be included in the top 5 best-performing facilities for PVC-only process vents for vinyl chloride, CDD/CDF, THC and total organic HAP. Had the malfunction not occurred, pollutant concentrations would have been even less than those determined during the time of testing and the facility would have still been included in the top 5 best-performing facilities. Therefore, we are including the OxyVinyls Pasadena facility in the MACT floor calculation for process vents.

We agree with commenters that the data submitted to the EPA in response to our August 21, 2009, CAA section 114 survey and testing request were collected under operating conditions of less than maximum capacity. Although commenters contended that the MACT floors should be adjusted for lower production levels in the final rules, commenters did not provide any empirical data or methodology to support modifying the limits. As such, we have no basis on which to consider revising the standards in response to this comment. We also agree with commenters that the testing schedule for our CAA section 114 request was compressed; however, commenters were not restricted from conducting additional testing and providing additional data to the EPA representing maximum operating conditions, yet, no such data were submitted. Accordingly, the EPA will use the data submitted by industry. Indeed, industry submitted 4 years of vinyl chloride resin data after the CAA section 114 testing request was completed and during the comment period.

We do not agree that the final rule should allow for new sources to come into compliance 3 years after the final rule is promulgated. The compliance date requirements for new and reconstructed sources are specified in the 40 CFR part 63 General Provisions at § 63.6(b).

Comment: Several commenters argued against combining the PVC major source MACT and area source GACT. One commenter argued that it was not Congress' intent to combine MACT and GACT requirements for sources listed in separate source categories, and that if this is going to be a trend moving forward, the EPA should undertake a separate rulemaking to identify and define, for public comment, the criteria it intends to use for combining major and area source categories. The other commenter stated that if the EPA chooses to make revisions to the limits for area sources, they should first remove area sources from the PVC MACT floor database and final rule and then reopen the PVC GACT rule to properly consider the available technology and impact of proposed revisions on small area sources. One commenter disagreed with the EPA's distinction between synthetic and natural area sources, arguing that because the CAA defines only two types of sources (major and area), any further distinctions are unlawful. Thus, they argue, the EPA's artificial distinction between true and synthetic area sources in order to include synthetic area sources in the PVC major source MACT floor database is unlawful and inconsistent with past agency practice. Furthermore, one commenter argues that by choosing to include synthetic area sources in the MACT floor analysis, the EPA is providing a strong disincentive for facilities to voluntarily reduce emissions to area source levels through enforceable permit limits. One commenter disputed all of the EPA's arguments for including synthetic area sources in the MACT floor:

(1) The commenter noted that the EPA stated that Congress did not expressly exclude synthetic area sources from MACT floor determinations. The commenter argued that Congress did not need to expressly exclude these sources because the sources were already excluded because they are not part of the major source category.

(2) The commenter further noted that the EPA has previously asserted that the definition of a major source, specifically the reference to a source's potential to emit considering controls allows the interpretation that a source's potential to emit before and after controls is relevant, such that synthetic minor sources may be considered within the meaning of the major source definition and included in the MACT floor determinations for categories for major sources. The commenter argued that the definition of what constitutes a major source allows a source's potential to emit to be determined while "considering controls" means only that a source may install controls and render itself an area source.

(3) The commenter referred to a floor statement of Senator Durenberger that the EPA cited to support its theory that the agency must take into account the "better" performing sources in setting the MACT floor. The commenter argued the statement demonstrates that it is the better performing sources within the source category that must be considered, and PVC area sources are not a part of the PVC major source category.

One commenter added that for the EPA to ignore distinctions between area and major PVC sources and use the OxyVinyls Deer Park facility in MACT floor calculations is unlawful. The commenter contended that the EPA incorrectly assumes the OxyVinyls Deer Park facility is a major source. The commenter stated that the facility is a "true" area source in contrast to the CertainTeed Mossville synthetic minor area source. The commenter contended that the CAA does not allow the distinction the EPA makes between synthetic and natural minor area sources, and the commenter provided detail of the regulatory history concerning major and area source classifications. The commenter provided additional detail regarding the classification of the OxyVinyls Deer Park and Certain Teed facilities, referencing previous communications with the EPA in which OxyVinyls informed the EPA that the OxyVinyls Deer Park facility is an area source. The commenter contended that the EPA cannot consider any PVC area sources in the major source PVC floor database because PVC major and PVC area sources are two separate source categories under the CAA. The commenter concluded by recommending the EPA recalculate the existing major source MACT floors, excluding the Deer Park and CertainTeed facilities.

Response: In the final rule, we have developed separate standards for major and area sources. We conducted a MACT floor analysis for major sources and a GACT analysis for area sources. Further discussion of the GACT analysis is provided in section V.H of this preamble.

We have reviewed data that OxyVinyls submitted to support their comment that their Deer Park, Texas facility is a "true" or natural area source. Based on the information provided, we are considering OxyVinyls Deer Park facility to be an area source for purposes of this rulemaking. Therefore, we are using data from this facility and from the CertainTeed facility in Mossville, Louisiana to establish area source GACT standards. However, we have also determined that the OxyVinyls Deer Park facility is a synthetic area source for the purposes of our analyses (without determining its status for any compliance purposes) because the facility routes emissions

from their process vents to a thermal oxidizer in series with an acid-gas scrubber. Without these controls, we would project the vinyl chloride and HCl emissions to be above the major source threshold. Similarly, for purposes of our analyses, we have determined that the CertainTeed facility is a synthetic area source because it uses controls, without which, their HAP emissions are projected to be above the major source threshold.

Even though the area source facilities would be subject to the area source standards, because they are synthetic area sources, we are including the information from both facilities in our analyses establishing the MACT floor level of control for major sources. As stated in the preamble to the proposed rule, the EPA maintains that including synthetic area sources in calculating the MACT floor is consistent with CAA section 112(d). Inclusion of synthetic area sources in the MACT floor determinations is also consistent with the agency's past practice in setting standards under CAA section 112(d). The inclusion of such sources affected the MACT floor level of control for the PVC-only HCl and PVC-Combined vinyl chloride and CDD/CDF process vents emission limits. Inclusion of synthetic area sources in the MACT floor determinations also affected the MACT floor level of control for the stripped resin limit for vinyl chloride and total non-vinyl chloride organic HAP in suspension and bulk resin. The vinyl chloride and total non-vinyl chloride organic HAP MACT floor emission limits for wastewater were also affected by inclusion of synthetic area sources.

Section 112(d) of the CAA directs the EPA to establish emission standards for each category or subcategory of major sources and area sources of HAP listed for regulation pursuant to section 112(c) of the CAA. Each such standard must reflect a minimum level of control known as the MACT floor. (See CAA section 112(d).) However, section 112 of the CAA does not specifically address synthetic minor or synthetic area sources, which include those sources that emit fewer than 10 tpy of any HAP or fewer than 25 tpy of any combination of HAP, because they use some emission control device(s), pollution prevention techniques or other measures (collectively referred to as controls in this preamble) adopted under federal or state regulations. If not for the enforceable controls they have implemented, synthetic area sources would be major sources under section 112 of the CAA.

We believe the better interpretation of the statutory language and legislative history is that synthetic area sources be included in MACT floor determinations. First, the plain language of the statute makes clear that our MACT floor determinations are to reflect the best sources in a category or subcategory. For new sources in a category or subcategory, the MACT floor shall not be less stringent than the emission control that is achieved, in practice, by the *best-controlled* similar source, as determined by the EPA. (See CAA section 112(d)(3).) For existing sources in a category or subcategory with fewer than 30 sources, the MACT floor may be less stringent than the floor for new sources in the same category or subcategory, but shall not be less stringent than the average emission limitation achieved by the *best-performing* 12 percent of the existing five sources (for which the Administrator has or could reasonably obtain emissions information)) in the category or subcategory. (See CAA section 112(d)(3)(A).) Thus, section 112(d)(3) of the CAA requires that MACT floors reflect what the best-controlled new sources and the best-performing existing sources achieve in practice. These phrases contain no exemptions and are not limited by references to sources with or without controls. Therefore, they suggest that all of the best-controlled or best-performing sources should be considered in MACT floor determinations, regardless of whether or not such sources rely upon controls.

Furthermore, section 112(d)(3) of the CAA expressly excludes certain sources that meet lowest achievable emission rate (LAER) requirements from MACT floor determinations for existing sources. (See CAA section 112(d)(3)(A).) The fact that Congress expressly excluded such LAER sources, but did not also exclude synthetic area sources suggests that no exclusion was intended for synthetic area sources. Indeed, nothing in the statute suggests that the EPA should exclude a control technology from its consideration of the MACT floor because the technology is so effective that it reduces source emissions such that the source is no longer a major source of HAP. (See 68 FR 2232, January 16, 2003, stating this rationale for including synthetic area sources in the floor determination for the final NESHAP for municipal solid waste landfills.)

Some commenters argue that because the PVC major and area source categories are separate, synthetic area sources (and natural (*i.e.*, non-synthetic) area sources) fall outside the regulated source category and should not be considered in MACT floor determinations. The EPA agrees that it listed PVC major and area source categories separately. (See 57 FR 31576, July 16, 1992, and 67 FR 43112, June 26, 2002.) However, the EPA disagrees that the CAA contemplates that synthetic area sources must be treated like true area sources and excluded from MACT floor determinations. Section 112(a) of the CAA defines a major source as: Any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants * * *. (See CAA section 112(a)(1).) An area source is defined as any stationary source of hazardous air pollutants that is not a major source. (See CAA section 112(a)(1).) In the major source definition, the EPA interprets the reference to a source's "potential to emit considering controls" as meaning that a source's potential to emit before and after controls is relevant, such that synthetic area sources may be considered within the meaning of this definition and included in MACT floor determinations for categories of major sources. Including synthetic area sources in MACT floor determinations ensures that MACT floors reflect the best-performing sources, as the CAA requires. The EPA also considered whether the reference to a source's potential to emit considering controls in the definition of major source necessarily means a source's potential to emit after controls have been implemented. While the EPA believes it is possible to read the phrase in this manner in isolation, such an interpretation would have the effect of excluding the best-performing sources from MACT floor determinations and, therefore, would be contrary to the statutory mandate that the EPA set MACT floors based on the levels the best-controlled new sources and the best-performing existing sources achieve in practice. The statutory reference to potential to emit considering controls should be read in a manner consistent with the other requirements of CAA section 112(d) to allow for the consideration of synthetic area sources in MACT floor determinations for major sources.

In addition, the legislative history suggests that synthetic area sources should be included in MACT floor determinations. In a floor statement, Senator Durenberger stated that in implementing section 112(d)(3) of the CAA, "the [Senate] managers intend the

Administrator to take whatever steps are necessary to assure that [the Administrator] has collected data on *all of the better-performing sources within each category.* [The Administrator] must have a data-gathering program sufficient to assure that [EPA] does not miss *any sources that have superior levels of emission control.*" (See Environment and Natural Resources Policy Division, Congressional Research Service, 103d Cong., S.Prt. 103–38 (prepared for the United States Senate Committee on Environment and Public Works), *A Legislative History of the Clean Air Act Amendments of 1990,* at 870, November 1993, emphasis added.) This statement underscores that Congress intended for MACT floor determinations to reflect consideration of all of the sources in each category with the best emission controls. It would be inconsistent with Congress's intent and the plain language of the CAA to exclude synthetic area sources—those sources with superior controls that became synthetic area sources by implementing such controls—from MACT floor determinations.

The inclusion of synthetic area sources in MACT floor determinations is justified because of the reasons explained above.

Accordingly, we did not exclude synthetic area sources from MACT floor determinations for major sources. For more information concerning MACT floors for the final standards, see section V.E.2 of this preamble and the memorandum, *Revised Maximum Achievable Control Technology (MACT) Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* in the docket.

Comment: Several commenters stated that dispersion resin limits should be based on measured concentration data and not calculated mass figures. Two commenters stated that the vinyl chloride limit proposed for dispersion resin was developed using a database that the EPA aggregated from producer submissions on a mass (pounds per day dry) basis and then re-divided by reported production volumes. The commenters listed several problems with the data used to convert the reported mass emissions to concentration limits by the EPA. The commenters recommended that the EPA simply use the underlying measured concentration data as the best and most accurate basis from which to develop the PVC MACT.

Response: For the final rule, we have revised the MACT floor-based emission limits for stripped resins. See section V.E.2 of this preamble.

Comment: One commenter stated they agree with the EPA's procedure for determining RDL. Another commenter contended that the EPA cannot justify its floor adjustment by asserting an inability to measure emissions below its triple-maximum-detection limit floor. The commenter stated that the record includes multiple sources that used lower detection limits; those sources demonstrate the feasibility of measuring emissions at lower levels. The commenter added that the agency specifies detection methods together with its standards; that detection method should have a known detection limit with a well-defined level of certainty. The commenter proposed that the agency could, accordingly, calculate its floor and as a second and independent step establish monitoring requirements that accommodate any imprecision associated with measurement, or it could utilize a safety factor. The commenter contended that the agency cannot, however, simply manipulate the limits according to standards that appear nowhere in the CAA.

Another commenter questioned the way in which the EPA addresses non-detects in air emissions. The commenter stated that multiplying by a factor of 3 is not presented in a clear way to show the rationale behind this calculation.

Response: As explained below, the final emissions limits were established using the RDL, which is based on an average, not the highest or lowest, of method detection levels for the best performing units. We agree with the commenter's suggestion to calculate the floor and then establish monitoring requirements to accommodate several factors, such as measurement precision near the detection limit.

We agree with many of the comments related to treatment of data reported as detection limit values in the development of MACT floors and emissions limits. The probability procedures applied in calculating the floor or an emissions limit inherently and reasonably account for emissions data variability including measurement imprecision when the database represents multiple tests from multiple emissions units for which all of the data are measured above the method detection level. That is less true when the database includes emissions occurring below method detection capabilities regardless of how those data are reported. The EPA's guidance to respondents for reporting pollutant emissions used to support the data collection specified the criteria for determining test-specific method detection levels.

Those criteria ensure that there is only about a 1-percent probability of an error in deciding that the pollutant measured at the method detection level is present when, in fact, it was absent. (See *Reference Method Accuracy and Precision (ReMAP): Phase 1, Precision of Manual Stack Emission Measurements*; American Society of Mechanical Engineers, Research Committee on Industrial and Municipal Waste, February 2001.) Such a probability is also called a false positive or the alpha, Type I, error. This means, specifically, that for a normally distributed set of measurement data, 99 out of 100 single measurements will fall within $\pm 2.54\ \sigma$ of the true concentration. The anticipated range for the average of repeated measurements comes progressively closer to the true concentration. More precisely, the anticipated range varies inversely with the square root of the number of measurements. Thus, if σ is the standard deviation of anticipated single measurements, the anticipated range for 99 out of 100 future triplicate measurements will fall within $\pm 2.54\ \sigma/\sqrt{3}$ of the true concentration. This relationship translates to an expected measurement imprecision for an emissions value occurring at or near the method detection level of about 40 to 50 percent.

By assuming a similar distribution of measurements across a range of values and increasing the mean value to a representative higher value (*e.g.,* 3 times MDL), we can estimate measurement imprecision at other levels. For an assumed 3 times the MDL, the estimated measurement imprecision for a 3-test-run average value would be on the order 10 to 20 percent. This is about the same measurement imprecision as found for EPA Methods 23 and 29 indicated in the ASME Precision of Manual Stack Emissions Measurements for the sample volumes prescribed in the final rule (*e.g.,* 4 to 6 dry standard cubic meters (dscm)) for multiple tests.

Analytical laboratories often report a value above the method detection limit that represents the laboratory's perceived confidence in the quality of the value. This arbitrarily adjusted value is expressed differently by various laboratories and is called limit of quantitation (LOQ), practical quantitation limit (PQL) or RL. In many cases, the LOQ, PQL or RL is simply a multiplication of the method detection limit. Multipliers range from 3 to 10. Because these values reflect individual laboratories' perceived confidence, and, therefore, could be viewed as arbitrary, we decline to adopt the LOQ, PQL or RL because such approaches in our view would inappropriately inflate the MACT

floor standards. Our alternative to those inconsistent approaches is discussed below.

Consistent with findings expressed in reports of emissions measurement imprecision and the practices of analytical laboratories, we believe that using a measurement value of 3 times a method's detection limit established in a manner that assures 99-percent confidence of a measurement above zero will produce a representative method RL suitable for establishing regulatory floor values.

On the other hand, we agree with commenters that an emissions limit determined from a small subset of data or data from a single source may be significantly different than the actual method detection levels achieved by the best-performing units in practice. This fact, combined with the low levels of emissions measured from many of the best-performing units, led the EPA to review and revise the procedure intended to account for the contribution of measurement imprecision to data variability in establishing effective emissions limits. In response to the comments and internal concerns about the quality of measurements at very low emissions limits especially for new sources, we revised the procedure for identifying an RDL

The revised procedure for determining an RDL starts with identifying all of the available reported pollutant specific method detection levels for the best-performing units regardless of any subcategory (*e.g.*, existing or new, fuel type, etc.). From that combined pool of data, we calculate the arithmetic mean value. By limiting the data set to those tests used to establish the floor or emissions limit (*i.e.*, best performers), we believe that the result is representative of the best-performing testing companies and laboratories using the most sensitive analytical procedures. We believe that the outcome should minimize the effect of a test(s) with an inordinately high method detection level (*e.g.*, the sample volume was too small, the laboratory technique was insufficiently sensitive or the procedure for determining the minimum value for reporting was other than the detection level). We then call the resulting mean of the method detection levels the RDL as characteristic of accepted source emissions measurement performance.

The second step in the process is to calculate 3 times the RDL to compare with the calculated floor or emissions limit. This step is similar to what we have used before including for the Portland cement MACT determination. We use the multiplication factor of 3 to reduce the imprecision of the analytical method until the imprecision in the field sampling reflects the relative method precision as estimated by the ASME ReMAP study. That study indicates that such relative imprecision remains a constant 10 to 20 percent, over the range of the method. For assessing the calculated floor results relative to measurement method capabilities, if 3 times the RDL were less than the calculated floor or emissions limit (*e.g.*, calculated from the UPL), we would conclude that measurement variability was adequately addressed. The calculated floor or emissions limit would need no adjustment. If, on the other hand, the value equal to 3 times the RDL were greater than the UPL, we would conclude that the calculated floor or emissions limit does not account entirely for measurement variability. Where such was the case, we substituted the value equal to 3 times the RDL for the calculated floor or emissions limit, which results in a concentration where the method would produce measurement accuracy on the order of 10 to 20 percent, which is similar to other EPA test methods and the results found in the ASME ReMAP study.

We determined the RDL for each pollutant using data from tests of all the best performers for all of the final regulatory subcategories (*i.e.*, pooled test data). We applied the same pollutant-specific RDL and emissions limit adjustment procedure to all subcategories for which we established emissions limits. We believe that emissions limits adjusted in this manner, which ensures that measurement variability is adequately addressed relative to compliance determinations, is a better procedure than the one applied at proposal, which was based on more limited data. We also believe that the currently available emissions testing procedures and technologies provide the measurement certainty sufficient for sources to demonstrate compliance at the levels of the revised emissions limits.

As for the commenter's suggestion that the EPA utilize a safety factor, the commenter provided no additional explanation of what a safety factor is, how it should be calculated and used, and no additional information to calculate such a factor.

Comment: One commenter stated that the EPA has set impossibly low limits for CDD/CDF, given the detection limits for EPA Method 23. Several commenters contended that, considering the body of available evidence on this subject, the EPA should not set limits below 0.1 nanogram toxic equivalent (TEQ) per dscm for CDD/CDF. Several commenters asserted that the CDD/CDF emission level of 0.023 nanograms per dry standard cubic meters (ng/dscm) proposed for PVC facilities is below levels that can be accurately measured.

Several commenters stated the EPA should impose work practice standards rather than emission limits to control CDD/CDF emissions or adjust the CDD/CDF standard to account for measurement uncertainty. One commenter stated that the EPA's decision to propose such conservative requirements for CDD/CDF testing is particularly surprising and unjustified in light of the EPA's own estimates of the very low overall reduction of CDD/CDF emissions that would be achieved by this rule. The commenter also noted that the EPA recognized the CDD/CDF dataset contains nearly 50-percent "non-detect" data. The commenter added that previous MACT rulemaking efforts for other comparable subparts, including the MACT rule for Hazardous Waste Combustors (40 CFR part 63, subpart EEE) or the Industrial Boiler and Process Heater MACT (40 CFR part 63, subpart DDDDD), typically allow for either a work practice standard or for one-time CDD/CDF emissions testing of units subject to the rule. In contrast, the commenter asserted that the EPA has not proposed to allow for work practice standards and other emission standards (*e.g.*, control of temperature in the air pollution control system and emission standards for vinyl chloride and HCl) to control CDD/CDF emissions in the PVC MACT rule and instead, proposes to establish CDD/CDF emission standards at or below the detection capabilities of EPA Method 23 along with expensive testing for CDD/CDF annually. The commenter further stated that because PVC-only plants have similar CDD/CDF emissions, PVC-only plants should not be subject to numerical limits for CDD/CDF emissions.

One commenter stated that section 112(h) of the CAA provides that "if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard * * * the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard" and also cited *Sierra Club* v. *EPA*, 479 F.3d 875, 883 (DC Cir. 2007). The commenter stated that the EPA must first make a determination that "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations," not that it lacks emissions data to set a limit. The commenter added they believe that PVC facilities face precisely the type of

technological constraints in measuring for CDD/CDF that require the use of work practice standards.

Response: The commenters are correct that, at proposal, 50 percent of the CDD/CDF dataset was at non-detect levels. However, with the addition of the EDC/VCM information submitted by industry in response to the CAA section 114 request for the EDC/VCM industry, that number has decreased to 38 percent. In comparison, 10 of the Boiler NESHAP subcategories in 40 CFR part 63, subpart DDDDD contained CDD/CDF datasets with non-detect values greater than 80 percent of the data, with most having non-detects greater than 90 percent of the data. As a result, the EPA determined that a work practice standard would be appropriate for the major source Boiler NESHAP. Likewise, in the final Mercury and Air Toxics Standards signed by the Administrator on December 16, 2011, the EPA established work practice standards for CDD/CDF because the significant majority of data from all the generating units were below the detection levels of the EPA test methods. Such is not the case for the PVC data. Given the significantly greater level of detected information for PVC process vents it is apparent that CDD/CDF can be detected in PVC process vent streams. Therefore, we maintain that numerical emission limits are appropriate rather than work practices to control CDD/CDF emissions from PVCPU process vents. As discussed previously, the emission limits for CDD/CDF have been revised, based on new data collected from EDC/VCM manufacturers and new subcategories. We reviewed much larger data sets of EPA Method 23 CDD/CDF test data and determined that representative detection levels equal to 0.018 ng/dscm are achievable for sample volumes less than or equal to 6 dscm. As a result, the final rule requires a CDD/CDF TEQ emission limit of 0.038 ng/dscm for PVC-only process vents at existing and new sources, 0.051 ng/dscm for PVC-combined process vents at existing sources, and 0.034 ng/dscm for PVC-combined process vents at new sources. We estimate that 10 out of 13 sources for which we have data are able to meet the emission limits without additional control. We are not prescribing a particular control technology for the remaining facilities. Affected sources may use any control technique to meet the CDD/CDF limits. We believe sources can use techniques such as enhanced vapor recovery prior to combustion as a means to reduce chlorinated compounds resulting in less chlorine available to form CDD/CDF. For the impacts estimate, we estimated the cost for enhanced vapor recovery (*e.g.*, condensers) prior to combustion. Cost and emission reductions estimation are documented in the memorandum, *Revised Costs and Emission Reductions for Major Sources in the Polyvinyl Chloride and Copolymers (PVC) Production Source Category.*

F. Emission Source Requirements

1. Process Vents

Comment: One commenter raised several issues with the proposed definition of process vent. First, the commenter argued that the definition of process vent is too broad and incorporates emission points that are already regulated under other sections of the rule. Specifically, the commenters contended that unloading and loading lines, samples, wastewater collection and treatment systems and "other process components prior to the resin stripper" should be removed from the definition of process vent because including them in the process vent definition is in conflict with the proposed definitions of batch and continuous process vents. The commenter contended that wastewater collection and treatment systems should be excluded because they would already be regulated under the wastewater provisions specified in 40 CFR 63.11965 and 40 CFR 63.11970 of the proposed rule. In the case of "other process components prior to the resin stripper," the commenter contended that this is too broad a term, and at a minimum, the EPA should clarify what is meant by this term in the context of the process vent definition. Instead of the current proposed definition, the commenter suggested the following definition for process vent: "Process vent means batch process vent or continuous process vent." The commenter also proposed that the definitions of batch and continuous process vents should provide an exclusion for gaseous streams routed to a fuel gas system. The commenter stated that because gaseous streams have a useful purpose and most other 40 CFR part 63 NESHAP exclude gaseous streams from the definition of a process vent, they should not be considered process vents in this rule.

Response: In the final rule, we have revised the definition of process vent, continuous process vent and batch process vent to provide additional clarification, and we have added a definition for miscellaneous vent. These revisions also provide additional consistency with the changes made to the affected source definition, the definition of PVCPU and the new definitions for PVC-only process vent and PVC-combined process vent. See section V.I of this preamble for a complete discussion of the revised and added definitions.

2. Equipment Leaks

Comment: Several commenters contended that the proposed requirement to have double mechanical seals and double outboard seals on rotating equipment is a beyond-the-floor control option and not a representation of the current control level within the industry. The commenters stated that there are no PVCPU that exclusively utilize double mechanical seals throughout the PVCPU, but instead these technologies are used in limited areas of the PVC production process and different technologies are used in other areas. The commenters added that because the proposed requirements are actually beyond-the-floor options, the revised rule should allow subject facilities the option to comply with all the provisions of the promulgated 40 CFR part 63, subpart UU MACT standard. The commenters also contended that installation of further controls will constitute a burden on facilities and will provide minimal benefits in the form of potential HAP emission reductions. One commenter pointed out that proposed 40 CFR 63.11915(b)(1) and (2) would require pump seal installations that are optional under 40 CFR 63.1026(e) of subpart UU. Likewise, they argued, proposed 40 CFR 63.11915(b)(5) would require agitator seal installations that are optional under 40 CFR 63.1028(e) of subpart UU. The commenter argued that the EPA should revise the pump and agitator seal section to be consistent with subpart UU.

Response: The proposed requirement that reciprocating pumps, reciprocating and rotating compressors and agitators be equipped with double seals, or equivalent, was in error. In the final rules, we have adopted the MACT floor level of control for equipment leaks for all components (which is compliance with 40 CFR part 63, subpart UU), which gives affected sources the option of installing double seals, or equivalent, or complying with the LDAR requirements of the equipment leak standards.

Comment: Several commenters opposed the proposed requirements for PRD that any release is an automatic violation. The commenters contended that this requires a costly retrofit with little additional environmental benefit. Commenters contended that this provision is in contradiction to a long-standing recognition by the EPA that

some PRD discharges are necessary; for example, they stated the current rule recognizes that proper operation of PRD (including using emergency relief valve discharges, currently exempted) is a necessary component of safe and responsible plant operation. One commenter recommended that the EPA revise the proposed language at 40 CFR 63.11915(c) to read "[a]ny release to the atmosphere from a pressure relief device in HAP service, except for an emergency relief discharge * * * constitutes a violation of this rule."

Several commenters added that in the affirmative defense requirements, the EPA acknowledges safety-related relief valve discharges. Commenters pointed out that the affirmative defense criteria state in 40 CFR 63.11895(a): "(4) If the excess emissions resulted from a bypass of control device components or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; * * * (6) All emissions monitoring and control systems were kept in operation, if at all possible, consistent with safety and good air pollution control practices." In addition, some commenters contended the low reportable quantity thresholds and Toxic Release Inventory reporting are adequate incentives for facilities to minimize discharge events, thus, allowing for affirmative defense is appropriate. The commenters stated other MACT standards like the HON and the Consolidated Air Rule also make allowances in the closed vent system bypass rules that account for safety-related pressure valve releases, and, thus, that in order to avoid unsafe conditions and prevent loss of life, personal injury or severe property damage, the EPA should allow facilities to claim an affirmative defense for safety-related releases.

Response: PRD releases are already prohibited at all PVC facilities by the part 61 NESHAP, except when ducted to a control device meeting the 10 ppm limit that applies to process vents or in an emergency relief discharge (40 CFR 61.65(a)). In this CAA section 112(d) NESHAP rulemaking, which builds upon the part 61 NESHAP, we have developed emission standards that are continuous and consistent with *Sierra Club* v. *EPA*. Commenters do not have any legal basis for failing to apply an emission standard to PRD releases. We believe that PRD releases at PVC facilities are caused by malfunctions or other occurrences. However, such circumstances do not justify commenters' suggestion that no standard applies to such releases. Further, the proposed affirmative defense would be available for PRD releases caused by malfunctions. Therefore, we are not exempting emergency PRD releases in the final rule. See *Sierra Club* v. *EPA*, 551 F.3d 1019 (D.C. Cir. 2008). Therefore, the final rule provides that a PRD release, unless ducted to a control device meeting the process vent limits, is a violation of the emission standard.

Release events from PRD have the potential to emit large quantities of HAP. In that case, it is important to identify and control any releases in a timely manner. Therefore, we are requiring you to install electronic indicators on each PRD that would be able to identify and record the time and duration of each pressure release. In addition to ensuring that significant releases are addressed, these requirements will also alert operators to any operational problems with the PRD seal that could be resulting in emissions to the atmosphere. Furthermore, if danger is imminent and a PRD releases to the atmosphere, facilities have the ability to assert an affirmative defense.

As discussed in the proposed rule, we are including an affirmative defense to civil penalties for exceedances of emission limits. See 40 CFR 63.12005 of the proposed rule (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are requiring that other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 63.11895 of the proposed rule. (See 40 CFR 22.24.) The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *." The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.11895 of the proposed rule and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *." In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR 22.77).

Comment: Several commenters argued that multiple systems and procedures already exist at facilities to detect and remedy releases from PRD and, thus, automatic release indicators are redundant. These commenters stated retrofitting existing PRD with release indicators would be costly, and installation of these devices will not result in any emission reduction because they are indicators only. Commenters contended that the PVC industry is currently subject to both environmental and safety standards that adequately address concerns with the detection of emissions from relief devices, such as 40 CFR part 61, subpart V requirements in 40 CFR 61.242–4. Two commenters pointed out that most PVC plants typically have rupture discs installed below relief valves that discharge to the atmosphere, and monitor the space between the rupture disc and the PRD for leaks on a routine basis using a local pressure indicator and log this information for safety purposes. One commenter contended that the EPA should at least perform a cost-benefit analysis before finalizing this requirement. Several commenters contended that given the cost, multiple systems currently in-place, and the lack of any emissions reductions, the EPA should delete the requirement for release indicators at proposed 40 CFR 63.11915(c).

Response: We acknowledge, based on information from the commenters, that the PVC industry typically installs area monitors in addition to rupture discs in series with relief valves. We also acknowledge other commenters' statements that multiple systems and procedures exist to detect and remedy releases from PRD, although they did not identify specific systems or procedures for the EPA to consider. However, the commenters did not suggest that the EPA adopt any type of

monitoring or recordkeeping requirement for PRD discharges, and commenters' statements taken as a whole do not support a conclusion that all PVC facilities currently install and use effective means to detect and record PRD discharges for all of their PRD.

Release events from PRD have the potential to emit large quantities of HAP, and a large number of these releases that may occur may not be identified and controlled in a timely manner, and may be due to repeat problems that have not been corrected. In the final rule, PRD are required to be equipped with indicators to identify and record the time and duration of each pressure release. The requirement to install indicators to identify and record the time and duration of each pressure release is a compliance requirement to ensure the PRD requirements in the final rule are met. They help ensure that any PRD discharge, *i.e.*, a release of uncontrolled HAP emissions, is immediately known to the source operator and recorded for future consideration by the facility or regulatory authority, so that remedial or preventative action can be taken to minimize or avoid PRD discharges in the future. The cost of the electronic indicators is incorporated into the costs of the final rule. Our cost estimates are based on the best information available to the EPA. While commenters indicated the EPA costs were underestimated, they did not provide sufficient information to revise our estimates.

Additional discussion on our decisions regarding PRD is found in the response to the previous comment.

3. Resin

Comment: One commenter noted that 40 CFR 63.11960(d)(2) and (3) of the proposed rule states that: "If an operating limit is a range, then you must operate the stripper as close as possible to the maximum or minimum operating limit for the resin stripper, whichever results in higher emissions (i.e., lower emission reduction)." The commenter added that the purpose of an operating range is to allow for normal variability and fluctuation inherent in the process, and by requiring that compliance measurements be performed at operating conditions resulting in the highest emissions, the agency is artificially increasing both the chance that a single compliance measurement would be out of compliance, as well as the overall emissions loading used to evaluate the environmental performance of the unit. The commenter submitted that such operating limits applied to resin strippers are inappropriate and that where conditions exist that operating limits are appropriate, proper measurement protocol would be to require sampling within the normal operating ranges, not at a particular point within.

Response: In the final rule, for stripped resins as well as for process wastewater, we are no longer requiring sources to comply with operating limits and conduct continuous parametric monitoring. The requirements to conduct resin sampling are sufficient to assure compliance with the stripped resin limits.

In our review of the resin sampling data in conjunction with the establishment of additional subcategories for stripped resins (see discussion above), we recognize that while resin subcategories are established at the type of resin, there are a multitude of resin grades produced by facilities that fall under a general resin type. Some facilities may produce on the order of hundreds of different grades for any one particular resin type. For the same reasons outlined as to why we are establishing additional subcategories for stripped resins in the final rule, we recognize that there are also differences in the formulations, recipes and processing conditions in the polymerization reactors and/or resin stripper for different resin grades of the same resin type. The establishment of resin subcategories at the grade level would be impractical because an inordinate number of subcategories would have to be established for hundreds, if not thousands, of different grades of resin. As such, the MACT limits established at the level of resin type will account for the inherent variability in not only the formulation and recipes of the different resin grades, but also the variation that must exist in the polymerization and stripping of different resin grades in order to meet established resin specifications and end-user requirements. The final rule requires that compliance with the stripped resin limits be demonstrated based on a 24-hour arithmetic average of samples taken every 3 hours for continuous strippers or at the end of each batch for batch strippers. The frequency of resin sampling that is required under the final rule is sufficient to ensure that continuous and batch stripping operations are in continuous compliance with the stripped resin limits.

Therefore, requiring facilities to establish parameters on their stripping operations that must be monitored and maintained to ensure continuous compliance is not practical considering the multitude of operating limits and ranges that would need to be established to cover the production of numerous grades of resin. We further recognize that given the establishment of resin limits at the outlet of the resin strippers, we can allow flexibility in the operation of the strippers while ensuring that the resin limits are being met as the resin exits the stripper. Therefore, we have removed all requirements for continuous parametric monitoring of resin strippers from the final rule.

Comment: One commenter contended that a work practice standard is needed for startup periods for the resin slurry strippers. The commenter does not normally take samples for vinyl chloride within 2 hours of a PVC resin slurry stripper startup, but provided a table of information in their comment letter on four investigations undertaken on different days at different plants. The commenter stated that the first three products tested were relatively easy-to-strip grades, while the fourth product was a relatively hard-to-strip pipe-grade resin. The commenter stated that a relatively short startup vinyl chloride spike is present for easy-to-strip resins, but that for the higher volume pipe grade resin with lower porosity (hard-to-strip), the startup spike lasted at least 1 hour and, possibly, 2 hours. The commenter contended that, based on the variability seen in the slurry stripper startups, it is not possible to set a single numerical limit for startup conditions. Therefore, the commenter requested that the EPA establish a work practice allowing a 2-hour time period following startup when no vinyl chloride samples shall be used for compliance purposes.

Response: The resin limits apply at all times including during periods of normal operation and during periods or startup and shutdown. The variability incorporated into the stripped resin limit calculation for each resin type will sufficiently allow for periods of concentration spiking during periods of startup. Compliance with the stripped resin limits is based on a 24-hour arithmetic average of samples taken every 8 hours for continuous strippers or at the end of each batch for batch strippers. For a continuous stripper, samples must be taken every 8 hours or for each grade, whichever is more frequent. We believe the 24-hour averaging time and 8-hour sampling frequency will allow sources to demonstrate compliance with the stripped resin limits. Finally, section 112(h) of the CAA authorizes the EPA to set work practice standards in lieu of numerical emission limits only where it is not feasible to prescribe or enforce a numerical emission standard. This statutory threshold is further defined to

mean that HAP cannot be emitted "through a conveyance designed and constructed to emit or capture such pollutant" or "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." The commenter did not provide any information to satisfy this statutory prerequisite to support the application of work practice standards to startup periods for resin strippers. Therefore, we disagree that a work practice should be established in lieu of a numerical emission limit for resin strippers during periods of startup.

4. Wastewater

Comment: Several commenters contended that owner/operators should be exempt from the proposed initial and continuous vinyl chloride and HAP sampling requirements if they can document, through process knowledge or historical sampling data, that no HAP are present in the wastewater stream. The commenters proposed that all documentation would be available to an inspector. Commenters contended that the HON at 40 CFR 63.144(b) and (c) (subpart G) allows for the use of sampling, bench scale data and/or process knowledge to determine concentration and flow rate of a wastewater stream.

Response: In the final rule, we are requiring that for any process wastewater streams that are not being treated prior to being discharged from the PVCPU, facilities must sample those streams and determine if treatment is required to meet the process wastewater limits for vinyl chloride and total non-vinyl chloride organic HAP. If, after the initial sampling, treatment is not required to meet the limits, then those streams must only be retested annually or when a process change is made. The final rule contains limits based on the MACT floor for total non-vinyl chloride organic HAP. The total HAP concentration and flow rate cutoffs were included as a beyond-the-floor option at proposal in an effort to make the wastewater requirements consistent with other chemical sector rules, because the option was cost-effective. Based on our evaluation of the total non-vinyl chloride organic HAP limits, we determined that the 1,000 ppmw threshold for total organic HAP, above which facilities would have been required to comply with the HON wastewater provisions, was not appropriate for the final rule as all streams must meet a limit for vinyl chloride and total non-vinyl chloride organic HAP, that, when combined (*i.e.*, 116.8 ppmw for existing sources and 0.30 ppmw for new sources), is much lower than the previously proposed 1,000 ppmw threshold. We, therefore, removed the total HAP flow rate cutoff and concentration cutoff, and flow rate determination requirements from the final rule. Annual re-sampling and testing of untreated streams is not overly burdensome and provides more reliable results than engineering estimates or process knowledge on which to determine whether at some point in the future, an untreated stream must be treated to meet applicable limits.

Comment: Some commenters stated that the EPA should provide exemptions for certain safety-related streams. The commenters contended that certain events may occur at a PVCPU that require the release and subsequent discharge of water, such as a fire or the use of eye wash stations and safety shower, and these activities have little to no chance of emitting HAP. The commenters stated that safety-related streams are identified in HON at 40 CFR 63.100(f)(1) through (11). In the absence of such exemptions, the commenters concluded that facility employees will be confused or hesitant because of a compliance dilemma at the worst possible time.

Several commenters asked for clarification about which in-process wastewater streams require control and treatment. Several commenters contended that maintenance wastewater streams should be regulated independently of process wastewater. The commenters stated that the capture of maintenance wastewater emissions is infeasible and thus warrants use of a work practice standard. The commenters stated that there are no known practical and effective methods for collecting and controlling fugitive emissions from a wastewater stream, which can vary considerably in HAP concentration and flow rate. Several commenters argued that maintenance wastewater should not have a prescribed limit, but should have work practices to remove residuals prior to generation. A commenter stated that maintenance activities are non-routine, highly variable activities that require the purging, clearing and cleaning of equipment in preparation for safe handling by personnel. Some commenters added that maintenance wastewaters include dilute concentrations of HAP because industry takes efforts to remove residual HAP before equipment is flushed. The commenters concluded that quantifying a concentration to establish compliance with a limit would be extremely difficult if not impossible, because the "acceptable" level would be based on the specific circumstances involved. The commenters added that other MACT standards like the HON and MON provide a separate management option for maintenance or turnaround wastewater.

The commenters contended that streams should be clearly defined by the point of determination (POD) and not the proposed point of generation (POG). The commenters added that the POG concept is not defined or explained within either the VCM NESHAP or the proposed PVC MACT. Other MACT standards related to chemical process industries provide for sampling at the POD and have exemptions in the rule related to the definition of wastewater.

Response: We agree with the commenters that it is not feasible to collect wastewater resulting from maintenance activities at PVC facilities such that it could be contained and routed to a wastewater treatment system. We disagree that maintenance wastewater generation activities are non-routine. We maintain that maintenance activities at PVC facilities are routine, but those activities result in the generation of wastewater in such a manner that it cannot be collected, enclosed and routed to a wastewater treatment system or otherwise managed in a controlled or enclosed system as process wastewater can. PVC facilities reported a variety of different work practices used for maintenance wastewater, but did not provide sufficient description or information necessary to determine the effectiveness of any one work practice alone or relative to other work practices. Furthermore, these streams can vary considerably in HAP concentration. Therefore, it is not feasible to prescribe or enforce an emission standard for maintenance wastewater and maintenance wastewater streams should be regulated separately from process wastewater. In the final rule, maintenance wastewater is not subject to the same requirements as process wastewater but instead is subject to work practice standards. We are incorporating into the final rule the maintenance wastewater work practice requirements used in other EPA standards, such as the HON. These work practice standards include preparing a description of maintenance procedures for management of wastewater generated from the emptying and purging of equipment in the process during temporary shutdowns for inspections, maintenance, and repair and during periods which are not shutdowns. As in the HON, facilities can effectively implement these work practices to prevent or mitigate the

emissions of HAP from wastewater generated during maintenance activities. We also agree that certain safety related activities that may generate a wastewater stream not be subject to the requirements for process wastewater. Therefore, we have added separate requirements in the final rule for maintenance wastewater streams. Furthermore, we have clarified that certain safety-related streams are not considered wastewater. These two revisions in the final rule are consistent with wastewater provisions in other MACT standards, such as the HON and MON. We have also removed all terminology related to "point of generation" and "point of determination." These terms created confusion for determining compliance with the standards. The final rule includes simplified language regarding where process wastewater streams must be tested to determine if treatment is required to meet the process wastewater limits. In the final rule, we are requiring that wastewater be measured immediately as it leaves a piece of process equipment and before being mixed with any other process wastewater stream. We have also clarified that the limits must be met before the process wastewater stream is discharged from the PVCPU.

5. Heat Exchange Systems

Comment: Several commenters stated that the proposed heat exchange systems monitoring methods are more restrictive than other 40 CFR part 63 NESHAP. The commenters suggested that the EPA broaden proposed leak testing and compliance requirements for cooling water supply (in closed-loop recirculation systems) and required heat exchange systems. The commenters identified several alternate compliance methods: (1) EPA Method 107, which focuses on vinyl chloride, not HAP, be included as a compliance option. Commenters contended that EPA Method 107, which is conducted on-site, allows for fast results (24 hours, while EPA SW–846 Method 8021B tests can take a week) and quicker repairs to any leaking exchange systems; (2) EPA SW–846 Method 8260B, which commenters said should replace EPA SW–846 Method 8021B. Commenters stated that EPA SW–846 Method 8260B has a more comprehensive target chemical list; test laboratories no longer have the equipment or personnel capable of performing EPA SW–846 Method 8021B; and EPA SW–846 Method 8021B is not incorporated by reference in 40 CFR 63.14 as is the TCEQ Modified El Paso Method.

Response: The leak action level for heat exchange systems is not an independent limit on emissions, but rather is used as an indicator that there may be a leaking component and as a trigger level to take further action to remedy the leak. As discussed in the preamble to the proposed rule, the leak action level and associated repair requirements for heat exchange systems are work practice standards under section 112(h) of the CAA and not numerical emission limits, similar to requirements applicable to equipment leaks. The proposed leak action levels and monitoring frequencies were established based on the information provided to us in responses to our August 21, 2009, CAA section 114 survey and testing request of the PVC industry and subsequent requests by us of the industry requesting clarification on heat exchange system monitoring practices used in the industry.

At proposal, we required measurement of total strippable VOC for detecting leaks of HAP into the cooling water, which are ultimately emitted downstream. Based on comments received, we have added an option for facilities to monitor their heat exchange systems using EPA Method 107, for vinyl chloride to monitor for leaks of total strippable VOC into cooling water. Vinyl chloride is the primary raw material in the manufacture of PVC and is present in all process streams. Therefore, if either total strippable VOC or vinyl chloride leaks are detected, repair of the leaks will control the leaks for all HAP. The process streams are cooled by cooling water in non-contact heat exchangers. If there is a leak of a process stream into the cooling water, for example, through a broken heat exchanger tube bundle, vinyl chloride concentrations would increase in the cooling water. A leaking process stream that contains other HAP in addition to vinyl chloride would also leak those other HAP into the cooling water. In a recirculating heat exchange system that contains a cooling tower, the cooling water is exposed to the atmosphere at the cooling tower. It is sufficient to establish a leak action level for heat exchange systems at PVC facilities based on a level of vinyl chloride that, if detected in the cooling water, would indicate a leak of the process stream and all HAP contained in that process stream into the system. Therefore, we determined that for this industry, vinyl chloride is also an appropriate indicator to determine if there is a leak in a heat exchange system. Furthermore, EPA Method 107 is an established method for the analysis of vinyl chloride in wastewater samples.

Our approach at proposal to determining a MACT floor for heat exchange systems was to calculate the average (arithmetic mean) leak action level from the five reported lowest leak action levels to determine the floor for existing sources, and the single lowest leak action level to determine the floor for new sources. Similarly, we looked at the range of monitoring frequencies and selected the median frequency from nine heat exchange systems for existing sources and the most frequent monitoring period for new sources. We have revised the leak action level at the MACT floor for existing sources based on the median leak action level for total strippable VOC from the top five lowest leak action levels reported. Similar to our approach to determining the MACT floor for equipment leaks, it is appropriate to evaluate the median of leak action levels instead of calculating the arithmetic mean. We determined that the leak action level for total strippable VOC for the existing source MACT floor is 50 ppbw. The lowest leak action level reported was also 50 ppbw and represents the revised MACT floor leak action level for new sources. Therefore, in the final rule, the leak action level for total strippable VOC in cooling water is 50 ppbw with monthly monitoring, for both existing and new sources. The methods used by facilities to monitor for VOC include the TCEQ Modified El Paso Method and EPA Method 624. In the final rule, we have revised the cooling water monitoring method from EPA SW–846 Method 8021B to EPA Method 624, but we have not changed the option to monitor using the TCEQ Modified El Paso Method.

To develop a leak action level for vinyl chloride, we looked at the leak action levels and monitoring frequencies reported by facilities that perform vinyl chloride monitoring using EPA Method 107. We determined a vinyl chloride leak action level based on the median leak action level reported by facilities that monitor for vinyl chloride. Those leak action levels range from 50 ppbw to 5,000 ppbw with monitoring frequencies between monthly and quarterly. To determine the MACT floor level of control, we conducted an analysis similar to the analysis conducted for equipment leaks; an analogous emission source that is fugitive in nature where control is a work practice and not an emission limit. The existing source MACT floor level of control for equipment leaks was calculated using the average (median) level of control of work practices at the best-performing five sources. We

determined that the median leak action level for heat exchange systems was 50 ppbw. The MACT floor analysis results in a leak action level for vinyl chloride for existing sources of 50 ppbw with monthly monitoring. The lowest leak action level reported was also 50 ppbw and represents the revised MACT floor for new sources. Therefore, in the final rule, the leak action level for total strippable VOC in cooling water is 50 ppbw with monthly monitoring, for both existing and new sources. This analysis is documented in the memorandum, *Revised Maximum Achievable Control Technology (MACT) Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* and is available in the docket.

6. Other Emission Sources

Comment: One commenter stated that in the preamble to the proposed rule, the EPA has indicated that for "other emission sources," requirements from part 61 NESHAP constituted the MACT floor level of control and that, in turn, was used to set the proposed limits, which requires complying with a vinyl chloride percent reduction. However, the commenter added, the rule requires sources to comply with a total HAP percent reduction, while the preamble only requires sources to comply with a vinyl chloride percent reduction. The commenter contended that sources have been using a method for sampling and detecting vinyl chloride for years, and measuring total HAP will introduce an additional layer of complexity to the compliance requirement. The commenter requested that the EPA review the rule language and make it consistent with the preamble language by replacing total HAP with vinyl chloride.

Response: In the final rule, as in the proposed rule, we are requiring work practices that require venting the emissions from process components and equipment through a closed vent system to a control device prior to opening to minimize emissions. This is typically achieved by sweeping the component or equipment several times with nitrogen to reduce the concentration of HAP in the vapor space of the component or equipment. These work practices will reduce emissions of all HAP present in the component or equipment prior to opening. In the final rule we are setting standards for this emission source based on vinyl chloride because the part 61 NESHAP, which constitutes the MACT floor level of control for reactor and equipment openings, requires work practices to specifically control vinyl chloride emissions. It is appropriate to continue to set the standards based on vinyl chloride because it will always be present at this emission point, and controlling it will control all other HAP.

Comment: Commenters stated that gasholders should not be regulated as storage vessels, but should be considered as surge control vessels, due to their process functions. Specifically, commenters contended that based on the CAA liquid storage definitions and associated requirements, gasholders do not meet the definitions of "fixed roof" storage vessel or "floating roof" storage vessel and, thus, recommended that gasholders be defined as surge control vessels in 40 CFR 63.12005. One commenter also agreed with the EPA that gasholder seal water should not be regulated as wastewater.

The commenters stated that it is impractical to measure gasholder fugitive emissions or route them to a stack, thus work practices should be used to control these gasholder emissions. One commenter recommended that the EPA regulate PVC MACT gasholders in the same way as other surge control vessels at 40 CFR part 63, subpart H. The commenters stated that the PVC MACT standard for gasholders should be a combination of equipment control and procedural requirements. The commenter described studies undertaken to determine the feasibility of certain control technologies like the use of floating objects to cover the water seal, finding that though these approaches can reduce emissions, they have drawbacks as well, and thus should be used in combination with procedural standards.

One commenter provided information related to emissions and controls for gasholders, as requested by the EPA in the preamble. The commenter stated that gasholders are important for safety and stability of the operation in the PVC process, with the process equipment specifically designed around gasholders to maintain safe pressure and gas flow to the closed vent and vinyl chloride recovery systems. According to the commenter, any changes to the design of the existing system could compromise safety procedures and would impose a burdensome capital investment. Finally, the commenter recommended the use of floating objects, such as balls, hallow disks, an oil layer or rubber mats, in the gasholder water seal for emissions reductions, because it is a flexible system that provides a consistent degree of control without creating additional waste management concerns.

Response: In the proposed rule, we requested comment on techniques to control emissions from gasholders. We reviewed the information submitted by the industry and have concluded that it is not feasible to prescribe or enforce an emission standard for emissions of vinyl chloride or other HAP from the water seal and the outside of the floating bell on gasholders. For PVC facilities that have gasholders, they are an integral part of the vinyl chloride recovery process and are connected to the closed vent system that collects and routes process vent emissions from process components to the vinyl chloride recovery system. After vinyl chloride recovery, any remaining process vent gasses are routed through the closed vent system to a control device. There are, however, emissions from gasholders that originate from the water seal and the outer portion of the floating bell that are fugitive in nature. The water seal contacts vinyl chloride and other HAP contained in the gasholder, and thus, there is the potential to emit HAP from the water in the gasholder seal and the thin film of water that accumulates on the outer surface of the floating bell. It is not technically practicable to route these emissions into or through a conveyance designed and constructed to capture and control them to an enforceable emission limit. Therefore, in the final rule, we are promulgating a work practice and equipment standard consistent with the provisions of section 112(h) of the CAA. In the final rule, we are requiring facilities to install and maintain floating objects on the surface of the gasholder water seal to minimize emissions of vinyl chloride and other HAP. We are also requiring facilities to develop a standard operating procedure for each gasholder to ensure that the floating objects are properly maintained and that emissions are minimized.

G. Initial and Continuous Compliance and Recordkeeping and Reporting

Comment: Three commenters stated that the EPA should remove CDD/CDF CEMS from the rule. The commenters contended that CDD/CDF CEMS technology is not well developed. One commenter stated that an EPA CDD/CDF CEMS study noted that, within the range of 1–10 ng/dscm, TEQ relative accuracy was reported between 23 percent and 75 percent. The commenter contended that the technology would not be useful with such a wide range of relative accuracy at the proposed limit. Another commenter stated that the technology is not commercially available in the United States. Another commenter indicated that monitors in use are mainly in other countries. Another commenter added that several of the available monitors are not continuous because they are not real

time and require using a third party lab for results.

Response: We agree with the commenter on the availability of CEMS for CDD/CDF. CEMS for CDD/CDF and HCl are still being developed and the EPA does not have specifications for the technology currently. In the final rule, we have removed the requirement for CDD/CDF and HCl CEMS, but have retained them as an option for existing and new sources once performance specifications have been promulgated.

H. Area Sources

Comment: One commenter stated that, if the PVC MACT and GACT are combined, the EPA needs to fully consider the cost of the MACT on area sources and modify the requirements to minimize the burden on area sources. The commenter stated that GACT standards required by CAA section 112(d)(5) are different from MACT standards under CAA section 112(d)(3) and, though the technologies employed in these facilities are similar, the EPA has not performed the required economic analysis in setting GACT. One commenter stated that, given the burdens on reduced workforces at smaller facilities, scaled-back requirements such as reduced stack testing frequency or reduced CPMS requirements are warranted and will have no negative impact on air emissions or compliance at area source facilities. The commenter added that the economic impact of the proposed PVC MACT on area sources makes these measures necessary for the facilities to remain financially viable.

One commenter stated that the proposed GACT standard for process vents for vinyl chloride and CDD/CDF are not appropriate or cost effective, based on small emissions reduction and high cost calculated in the EPA's analysis. The commenter added that these limits are redundant since total organic HAP includes vinyl chloride and CDD/CDF and, thus, they contended that the vinyl chloride standards should be eliminated.

One commenter made several comments regarding the pollutants proposed for regulation for area sources under GACT. The commenter stated that regulation of "total HAP" and "CDD/CDF" under the area source GACT standard is not warranted because, although the agency has discretion to regulate all urban HAP for area sources, total HAP is not an urban HAP (they contend that classifying total HAP as an urban HAP would make the list meaningless), and CDD/CDF is not a HAP at all (thus, the EPA has no authority to regulate CDD/CDF under CAA section 112). Furthermore, the commenter contended that control technologies already used by CertainTeed to control vinyl chloride also achieve control of individual organic HAP. For CDD/CDF, the commenter pointed out that the EPA's own analysis showed that the proposed regulation would achieve little, if any, reductions. The commenter concluded that there is no benefit to establishing a standard for total HAP or CDD/CDF. The commenter added that the regulation of HCl under the area source GACT standard is not warranted either. They contended that, because the EPA has the discretion to revise the GACT standard only as necessary, the EPA must first determine that regulation of HCl is necessary. Instead, the commenter stated that the EPA seeks to regulate HCl emissions and suggests that such regulation is "appropriate" simply based on the fact that such emissions "are generated." In light of this, the commenter concluded that the proposed GACT standards for HCl should not be finalized.

Response: We proposed GACT standards for PVC area sources based on the proposed MACT standards for major sources. For the final rule, we have updated our analysis of area source GACT, considering comments received, including our analysis of cost considerations. Our revised GACT analysis assesses each PVC emission point (*e.g.*, process vents, stripped resin, equipment leaks, etc.) individually, for both existing and new sources, to determine the appropriate level of control, considering cost and emission reduction. The GACT analysis was conducted for the same subcategories as major sources.

Section 112(d)(5) of the CAA authorizes the EPA to promulgate standards or requirements for area sources "which provide for the use of generally available control technologies or management practices [GACT] by such sources to reduce emissions of hazardous air pollutants." We issued such standards for PVC area sources in 2007.

Under CAA section 112(d)(6), we are required to "review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years." With this rulemaking, we are fulfilling our obligation to review and revise, as necessary, the PVC Production area source standards. The 2007 NESHAP for PVC Production area sources (40 CFR part 63, subpart DDDDDD) are based on GACT. The area source NESHAP set emission limits only for vinyl chloride, which was the pollutant for which we needed the PVC production area source category to meet our 90-percent obligation in CAA sections 112(c)(3) and (k)(3)(B). In this final rule, we are tightening emission standards for vinyl chloride under CAA section 112(d)(6). We are also establishing emission standards for CDD/CDF and THC for process vents (with an alternative compliance limit for total organic HAP) and total non-vinyl chloride organic HAP for stripped resins and wastewater under CAA section 112(d)(5). We are also requiring generally available management practices for PVC area sources under CAA section 112(d)(5). We are not setting separate limits for HCl from process vents at PVC area sources.

In this final rule, we have determined that area source emission limits should be set for THC as a surrogate for organic HAP, along with limits for CDD/CDF and vinyl chloride, for process vents, and for total non-vinyl chloride organic HAP and vinyl chloride for stripped resins and process wastewater. We discussed earlier in this preamble our specific reasons for establishing emissions limits for these pollutants from PVC facilities. We also determined that it is appropriate to provide a total organic HAP limit as an alternative to the THC limit for process vents at area sources, just as we did for PVC major sources. We disagree with the commenter who states that the EPA should not establish a total organic HAP limit (or total non-vinyl chloride organic HAP limit for stripped resins and process wastewater) because total organic HAP is not an urban HAP. We note that the commenter concedes that the agency has discretion to regulate all urban HAP for area sources. The commenter also does not dispute that PVC facilities emit several organic urban HAP, beyond vinyl chloride.

Moreover, as the EPA has explained in other area source rules, the agency has authority to regulate all HAP, not only urban HAP, from area source categories listed pursuant to CAA section 112(c)(3). See, *e.g.*, Chemical Manufacturing Area Sources NESHAP proposed rule, 73 FR 58352, 58358, October 6, 2008, and final rule, 74 FR 56008, 56017–18, October 29, 2009).[4]

[4] CAA section 112(d)(5) states that for area sources listed pursuant to CAA section 112(c), the Administrator may, in lieu of CAA section 112(d)(2) "MACT" standards, promulgate standards or requirements "applicable to sources" which provide for the use of GACT or management practices "to reduce emissions of hazardous air pollutants." This provision does not limit the agency's authority to regulating only urban HAP

We are setting emission limits for total organic HAP for process vents (and total non-vinyl chloride organic HAP for stripped resin and process wastewater) for several reasons. First, the compliance measures that we expect sources to adopt to meet the final limits are equally effective at controlling emissions of non-urban organic HAP as urban organic HAP. Second, there is little, if any, additional cost for implementing those compliance measures at PVC process vents, stripped resin and process wastewater. Third, we are applying the standards to total organic HAP or total non-vinyl chloride organic HAP because many of the area sources emit a significant amount of non-urban organic HAP in addition to urban organic HAP, for example, the nationwide ratio of total organic HAP to urban organic HAP at affected area sources is more than 3 to 1. Finally, we believe our approach is consistent with certain industry comments that support using total organic HAP limits as the best means of achieving HAP emission reductions under CAA section 112(d) without fundamentally changing the PVC product being produced for sale by these facilities.

We have determined that area sources will not have to install different controls or implement different compliance strategies and will incur little, if any, additional cost to comply with the standards for total organic HAP (and total non-vinyl chloride organic HAP). Moreover, the commenter does not refute that the expected compliance measures in the PVC industry are equally effective at removing non-urban organic HAP, as urban organic HAP. For all of these reasons, we are applying these standards to process vents, stripped resin and process wastewater at PVC area sources. In addition, the comment that we should limit area source standards to only the urban organic HAP conflicts with other industry comments advocating THC as a surrogate. As we explained previously in preamble section V.C, THC is a reasonable surrogate for controlling all organic HAP from PVC process vents. However, while control of THC ensures control of all organic HAP (as does the total organic HAP alternative), THC cannot differentiate between organic HAP that is urban HAP and organic HAP that is not urban HAP. The commenter's statement further conflicts with our determination that a total non-vinyl chloride organic HAP emission limit is an appropriate limit for stripped resins and process wastewater (see discussion at preamble section V.C).

We disagree with the commenter's statement that CDD/CDF is not a HAP. We are authorized to regulate the CDD/CDF class of HAP. While dibenzofuran and 2,3,7,8-TCDD are identified by name as HAP in CAA section 112, all CDD/CDF are polycyclic organic matter and, as such, we have the authority to regulate these compounds.

We disagree with the commenter who stated reduced stack testing frequency or reduced CPMS requirements are warranted for area sources. We believe that these requirements are necessary to demonstrate compliance with the emission limits regardless of the size of the facility or the magnitude of emissions. Therefore, the same testing and monitoring requirements apply to both major and area sources. Since the PVC-only and PVC-combined process vent area source limits are based on the facility in each subcategory, no additional controls would be needed and no emission reductions would occur. Monitoring, recordkeeping and reporting would be the only costs. (See Tables 16 and 17 of this preamble.) We agree with the commenter that total organic HAP includes vinyl chloride and dioxins and furans, but we disagree that vinyl chloride standards should be eliminated, since vinyl chloride emissions limits already apply to PVC facilities under 40 CFR part 61, and they serve as a check on a unit's recovery process efficiency and since physical measurement of vinyl chloride from process vents occurs only every 5 years. In determining what constitutes GACT for this final rule, we considered the control technologies and management practices that are generally available to PVC area sources by examining relevant data and information, including information collected from PVC area sources. We also considered the control measures applicable to PVC major sources to determine if the control technologies and management practices are transferable and generally available to area sources. As part of the GACT determination, we considered the costs and economic impacts of available control technologies and management practices on area sources which are documented in the technical memorandum, *Generally Achievable Control Technology (GACT) Analysis for Area Sources in the Polyvinyl Chloride and Copolymers (PVC) Production Source Category, which is available in the docket.*

Under CAA section 112(d)(5), the EPA can promulgate standards or requirements for area sources "which provide for the use of generally available control technologies or management practices [GACT] by such sources to reduce emissions of hazardous air pollutants." Additional information on GACT is found in the Senate report on the legislation (Senate Report Number 101–228, December 20, 1989), which describes GACT as:

> * * * methods, practices and techniques which are commercially available and appropriate for application by the sources in the category considering economic impacts and the technical capabilities of the firms to operate and maintain the emissions control systems.

Consistent with the legislative history, we can consider costs and economic impacts in determining GACT.

Determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. We also consider the standards applicable to major sources in the analogous source category to determine if the control technologies and management practices are transferable and generally available to area sources. In appropriate circumstances, we may also consider technologies and practices at area and major sources in similar categories to determine whether such technologies and practices could be considered generally available for the area source categories at issue.

We determined new and existing area source standards for each emission point by evaluating the current (also referred to as baseline) level of control and control options beyond the current level of control.

For each emission point, we determined the current level of control for existing area sources, incorporating variability. If no area source currently exists in the category or subcategory, the least controlled major source, in each subcategory for each regulated pollutant, as applicable, was analyzed as the baseline level of control for GACT. The only two existing PVC area sources that we are aware of produce bulk resin and suspension resin, respectively. No existing area sources produce dispersion resin, suspension blending resin or copolymer resin. However, if an existing PVC major source is able to become a synthetic area source, *e.g.*, by taking a federally enforceable limit on its potential to emit, before the first compliance date of this rule, it would be subject to area source rather than major source PVC NESHAP requirements. Therefore, in order to develop GACT standards for other stripped resin subcategories, we determined the baseline level of control for these subcategories in which there is

emissions for which the category was listed under CAA section 112(c)(3).

no existing area source to be equivalent to that of the least controlled major source, *i.e.*, for the dispersion, suspension blending and copolymer subcategories for stripped resins. For the suspension blending and copolymer subcategories, there is only one major source. So for these subcategories of stripped resin, the level of control of the least controlled major source was the same as the major source MACT floor level of control. In addition, gasholders are the only emission source that are located at major sources, but not located at area sources. Therefore, we determined that the baseline level of control for gasholders is equivalent to that of the least controlled PVC major source with a small gasholder. We believe that all future possible existing area sources should be able to achieve these levels of control, as we predict that most, if not all, such sources will be major sources that limit their potential to emit to levels below the major source thresholds before the first substantive compliance date of this rule. See 42 U.S.C. 112(a)(1); 40 CFR 63.2 (definition of "potential to emit"). For equipment leaks, heat exchange systems and storage vessels, we determined that the level of control was the same as the major source work practice standards.

We are also establishing new source GACT. We have data from the two existing area source facilities, and those facilities form the basis of our new source GACT analysis. For the PVC-combined process vents, PVC-only process vents, bulk resin and suspension resin subcategories, we have data from one area source facility. For the other emission points (except for dispersion resin, suspension blending resin and copolymer resin discussed in the previous paragraph) both facilities are equivalent in terms of their current level of control. For equipment leaks, the CertainTeed Lake Charles facility and the OxyVinyls Deer Park facility both comply with 40 CFR part 61, subpart V. Therefore, we find that the level of control for new area sources is equivalent to the level of control for existing area sources.

Control options beyond the current or baseline level of control for existing sources were analyzed on a basis of cost effectiveness. We determined the emission reductions, if any, associated with existing PVC area sources meeting levels of control more stringent than the current or baseline level of control. We then estimated the annual cost of testing, monitoring, recordkeeping and reporting, and any operating and maintenance costs associated with control devices required to meet the more stringent control levels. We developed a cost- effectiveness estimate by dividing the annual cost of the more stringent control level with the annual emission reduction. The control options analyzed are as follows:

For PVC-only and PVC-combined process vents at new and existing area sources, for each subcategory, we analyzed two additional control options beyond the current level of control. The first option was requiring the current level of control, as discussed above, and the testing and monitoring requirements for process vents at existing major sources. The same types of controls are used at both existing area and major sources. The testing and monitoring necessary to ensure compliance with the emission limits and to ensure proper operation of the control device are the same regardless of the size of the control device. The second option was requiring meeting the emission limits for existing major sources in addition to the testing and monitoring requirements for existing major sources.

For PVC-only process vents at new and existing area sources, we determined that the second option was not cost effective; instead, we concluded that the first option was appropriate. We determined that the major source testing and monitoring requirements are appropriate and necessary to ensure that area sources are in compliance with the process vent standards, whether those required standards are the current level of control or major source standards. Therefore, we are requiring PVC-only and PVC-combined process vents at new and existing area sources to comply with GACT by meeting the current level of control and the testing and monitoring requirements for existing major sources.

For stripped resins at new and existing PVC area sources, we analyzed two additional control options beyond the current or baseline level of control for each subcategory. The first option was requiring the current or baseline level of control and the testing and monitoring requirements for stripped resins at existing major sources. The second option was meeting the emission limits for existing major sources in addition to the testing and monitoring requirements for existing major sources. For the bulk and suspension resin subcategories, we are setting the stripped resin limits for new and existing area sources equivalent to their current level of control, accounting for variability, and testing and monitoring requirements for major sources for each stripped resin subcategory. For dispersion resins, GACT is based on the baseline level of control, i.e., the least controlled major source and limits were developed for dispersion resins based on data from that source. For the suspension blending and copolymer resin subcategories, we are requiring the emission limits for existing major sources since there was only one source in each of these subcategories (*i.e.*, the baseline level of control was the level of control the existing major source) in addition to the testing and monitoring requirements for existing major sources. Similar to process vents, we determined that it is appropriate to require testing and monitoring requirements for major sources to ensure compliance.

For process and maintenance wastewater at new and existing PVC area sources, we analyzed three additional control options beyond the current baseline. The first option was requiring the current level of control and the testing and monitoring requirements for wastewater at existing major sources. The second option was meeting the emission limits for existing major sources in addition to the testing and monitoring requirements for wastewater at existing major sources. The third option was meeting the emission limits for new major sources in addition to the testing and monitoring requirements for wastewater at existing major sources. We determined that the second option of emission limits for existing major sources was less stringent than (i.e., not beyond) the current baseline for new and existing area sources. We determined that the third option of emission limits for new major sources were not cost effective for new or existing PVC area sources. Therefore, we are requiring process and maintenance wastewater at new and existing area sources to comply with GACT by meeting the current baseline and the major source testing and monitoring requirements. Similar to process vents, we determined that it is appropriate to require testing and monitoring requirements for major sources and necessary to ensure that area sources are in compliance with the process and maintenance wastewater standards.

For equipment leaks and for heat exchangers at new and existing PVC area sources, we analyzed one additional control option beyond the current level of control. The additional option was meeting the emission standards for equipment leaks and for heat exchangers at existing major sources. We determined that the emission standards for equipment leaks and heat exchangers at existing major sources are cost effective for new and existing area sources. Therefore, we are requiring new and existing area sources to comply with GACT by meeting the

equipment leak and heat exchanger standards at existing major sources.

For storage tanks at new and existing PVC area sources, we analyzed one additional control option beyond the current baseline. The additional option was meeting the emission standards for storage tanks at existing major sources. We determined the emission standards for storage tanks at existing major sources are cost effective for new and existing area sources. Therefore, we are requiring new and existing area sources comply with GACT by meeting the emission standards for existing major sources.

For other emission sources, the current level of control is emission standards for reactor and other equipment openings equivalent to the requirements in 40 CFR part 61, subpart F, which is also equivalent to the major source level of control. We analyzed an additional option for gasholders equivalent to the emission standards for gasholders at major sources. The option was determined to be cost effective for new and existing area sources. Therefore, we are requiring that new and existing area sources comply with GACT by meeting the emission standards for gasholders and reactor openings at major sources.

Tables 16 and 17 present a summary of the control options analysis for new and existing area sources.

TABLE 16—SUMMARY OF CONTROL OPTION ANALYSIS FOR EXISTING AREA SOURCES

Emission point	Control option analyzed beyond current level of control	Incremental annual cost of compliance ($/yr)	Emission reductions (tpy—total HAP)	Cost effectiveness ($/ton total HAP)
PVC-only process vents	Major Source Testing and Monitoring	10,890	0	[a]
	Existing Major Source emission standards, monitoring and testing	180,245	0.257	701,814
PVC- combined process vents.	Major Source Testing and Monitoring	10,890	0	[a]
	Existing Major Source emission standards, monitoring and testing	10,890	0	[a]
Stripped resins (all subcategories).	Major Source Testing and Monitoring	10,615	0	[a]
	Existing Major Source emission standards, monitoring and testing	10,615	0	[a]
Process and maintenance wastewater.	Major Source Testing and Monitoring	19,777	0	[a]
	Existing Major Source emission standards, monitoring and testing	19,777	0	[a]
	New Major Source emission standards, monitoring and testing	2,996,390	12.2	245,516
Equipment leaks	Existing Major Source emission standards, monitoring and testing	72,525	9.29	7,807
Heat exchangers	Existing Major Source emission standards, monitoring and testing	25,529	15.1	1,691
Other emission sources	Existing Major Source emission standards, monitoring and testing	3,108	0	[b] $4,921
Storage tanks	Existing Major Source emission standards, monitoring and testing	3,108	0	[c] 2,000–12,000

[a] Option does not result in emission reductions; therefore, a cost effectiveness was not applicable.

[b] Emission reductions and costs were calculated for retrofitting a model small gasholder with floating objects to reduce emissions from the gasholder water seal. The results of the analysis showed that cost effectiveness was equal to $4,921 per ton of vinyl chloride reduced. We are not aware of any gasholders operated at existing PVC area sources; therefore no emission reductions are shown.

[c] Emissions reductions and costs were calculated for retrofitting 40 CFR part 63, subpart WW controls on model fixed roof tanks meeting 40 CFR part 60, subpart Kb vapor pressure and size parameters. The results of the analysis showed that cost effectiveness ranged from $2,000 to $12,000 per ton of HAP reduced by this option depending on the number of turnovers assumed. Based on information submitted by PVC production facilities, no storage vessels from affected sources that meet the capacity levels storing materials that meet the vapor pressure levels were identified. Therefore, it was assumed that no storage vessels meeting capacity levels storing materials that meet the vapor pressure levels would be constructed at a new source.

$/yr—dollars per year.

tpy—tons per year.

$/Ton Total HAP—dollars per ton of total HAP.

TABLE 17—SUMMARY OF CONTROL OPTION ANALYSIS FOR NEW AREA SOURCES

Emission point	Control option analyzed beyond current level of control	Incremental annual cost of compliance ($/yr)	Emission reductions (tpy—total HAP)	Cost effectiveness ($/ton total HAP)
PVC-only process vents	Major Source Testing and Monitoring	10,890	0	[a]
	Existing Major Source emission standards, monitoring and testing	180,245	0.257	701,814
PVC-combined process vents.	Major Source Testing and Monitoring	10,890	0	[a]
	Existing Major Source emission standards, monitoring and testing	10,890	0	[a]
Stripped resins (all subcategories).	Major Source Testing and Monitoring	10,615	0	[a]
	Existing Major Source emission standards, monitoring and testing	10,615	0	[a]
Process and maintenance wastewater.	Major Source Testing and Monitoring	9,888	0	[a]
	Existing Major Source emission standards, monitoring and testing	9,888	0	[a]
	New Major Source emission standards, monitoring and testing	1,988,368	8.91	223,169
Equipment leaks	Existing Major Source emission standards, monitoring and testing	36,263	4.64	7,807
Heat exchangers	Existing Major Source emission standards, monitoring and testing	12,764	11.4	1,117
Other emission sources	Existing Major Source emission standards, monitoring and testing	3,032	0.616	4,922

TABLE 17—SUMMARY OF CONTROL OPTION ANALYSIS FOR NEW AREA SOURCES—Continued

Emission point	Control option analyzed beyond current level of control	Incremental annual cost of compliance ($/yr)	Emission reductions (tpy—total HAP)	Cost effectiveness ($/ton total HAP)
Storage tanks	Existing Major Source emission standards, monitoring and testing	1,554	0	[b] 2,000–12,000

[a] Option does not result in emission reductions; therefore, a cost effectiveness was not applicable.
[b] Emissions reductions and costs were calculated for retrofitting 40 CFR part 63, subpart WW controls on model fixed roof tanks meeting 40 CFR part 60, subpart Kb vapor pressure and size parameters. The results of the analysis showed that cost effectiveness ranged from $2,000 to $12,000 per ton of HAP reduced by this option depending on the number of turnovers assumed. Based on information submitted by PVC production facilities, no storage vessels from affected sources that meet the capacity levels storing materials that meet the vapor pressure levels were identified. Therefore, it was assumed that no storage vessels meeting capacity levels storing materials that meet the vapor pressure levels would be constructed at a new source.
$/yr—dollars per year.
tpy—tons per year.
$/Ton Total HAP—dollars per ton of total HAP.

A detailed discussion of these options and the cost and impacts estimated for them is found in the memorandum, *Generally Achievable Control Technology (GACT) Analysis for Area Sources in the Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* and is available in the docket. The results of the GACT analysis are presented in sections VI.A and VI.B of this preamble.

The summary of the area source requirements in the final rule is discussed in section IV.I of this preamble.

Comment: One commenter disagreed with the EPA's proposed equipment leak standards. The commenters stated that the EPA's estimates of baseline fugitive emissions are not valid and not representative of CertainTeed's actual measured fugitive emissions from equipment leaks, because EPA estimated the emissions from equipment leaks by applying average emission factors instead of relying on actual measured data. The commenter contended that because of these estimates, the EPA grossly overestimated the level of fugitive emission reductions. The commenter concluded that because of these overestimations, the cost of the proposed Equipment Leak GACT standards cannot be justified by the potential emission reductions.

Response: At proposal, we estimated baseline emissions and reductions for fugitive emissions from equipment leaks using the 1995 EPA *Protocol for Equipment Leak Emission Estimates.* We agree with the commenter that the 1995 factors yield conservatively high estimates of actual emissions. As part of the technology review required by section 112(d)(6) of the CAA, the EPA has developed new emission factors for equipment leaks that better represent fugitive emissions at chemical manufacturing processes and petroleum refineries. Emission factors were developed using facility data from the MON MACT floor development and the EPA Office of Air Quality and Planning Standards Protocol for Equipment Leak Emission Estimates. (Please refer to the memorandum in the docket titled *Technology Review for Equipment Leaks* for additional information regarding the development of new emission factors for equipment leaks.) Although the commenter provided annual fugitive emissions from equipment leaks for years 2007 through 2010, the commenter did not provide any equipment leak monitoring records, test reports or additional documentation supporting their emission estimates. Therefore, we have chosen to estimate fugitive emissions for both major and area sources using the updated emission factors for consistency across all PVCPU. Using updated emission factors and equipment counts provided by CertainTeed where available, we have updated the baseline emission estimate for fugitive HAP emissions from equipment leaks at the CertainTeed facility to 10 tpy. We have also updated our emissions reduction estimate to 4.64 tpy of HAP as a result of the facility complying with 40 CFR part 63, subpart UU.

We have also updated the total capital investment and total annualized costs of the CertainTeed facility complying with 40 CFR part 63, subpart UU and installing and operating a PRD monitoring system using equipment counts where provided by the facility. The analysis is documented in the memorandum titled *Generally Achievable Control Technology (GACT) Analysis for Area Sources in the Polyvinyl Chloride and Copolymers (PVC) Production Source Category* in the PVC docket. The total cost effectiveness is estimated to equal $6,840 dollars per ton of total HAP; therefore, we are finalizing the requirements for area sources to comply with subpart UU and install and operate a PRD monitoring system.

I. Definitions

The following definitions have been revised since the proposal: Batch process vent, conservation vent, continuous process vent, grade, in HAP service, operating scenario, polyvinyl chloride, PVC production process unit or PVCPU, polyvinyl chloride copolymer, pressure relief device, process vent, solution process, type of resin and wastewater.

We have revised the definition of *batch process vent* to provide consistency with our revisions to the definitions of continuous process vent and process vent and to clarify that batch process vents must be routed to a closed vent system and control device. We also clarify that all emission episodes associated with a batch unit operation are part of the batch process vent. We have also removed language from the definition that excluded certain types of vents or vents from certain components or equipment. In the final rule, *batch process vent* means a vent from a batch operation from a PVCPU through which a HAP-containing gas stream has the potential to be released to the atmosphere except that it is required by this subpart to routed to a closed vent system and control device. Emissions for all emission episodes associated with the unit operation(s) are part of the batch process vent. Batch process vents also include vents with intermittent flow from continuous operations. Examples of batch process vents include, but are not limited to, vents on condensers used for product recovery, polymerization reactors and process tanks.

We have revised the definition of *conservation vent* to provide additional clarification. In the final rule, *conservation vent* means an automatically operated (*e.g.*, weight-loaded or spring-loaded) safety device used to prevent the operating pressure of a storage vessel from exceeding the maximum allowable working pressure of the process component. Conservation vents must be designed to open only when the operating pressure of the storage vessel exceeds the maximum allowable working pressure of the process component. Conservation vents open and close to permit only the intake or outlet relief necessary to keep the storage vessel within permissible working pressures, and reseal automatically.

We have revised the definition of *continuous process vent* to provide consistency with our revisions to the definitions of batch process vent and process vent. We also clarify that continuous process vents must be routed to a closed vent system and control device. In the final rule, *continuous process vent* means a vent from a continuous PVCPU operation through which a HAP-containing gas stream has the potential to be released to the atmosphere, except that it is required by this subpart to routed to a closed vent system and control device and has the following characteristics:

(1) The gas stream originates as a continuous flow from any continuous PVCPU operation during operation of the PVCPU.

(2) The discharge into the closed vent system and control device meets at least one of the following conditions:

(i) Is directly from any continuous operation.

(ii) Is from any continuous operation after passing solely (*i.e.*, without passing through any other unit operation for a process purpose) through one or more recovery devices within the PVCPU.

(iii) Is from a device recovering only mechanical energy from a gas stream that comes either directly from any continuous operation or from any continuous operation after passing solely (*i.e.*, without passing through any other unit operation for a process purpose) through one or more recovery devices within the PVCPU.

We have revised the definition of *grade* to specify resin "type" instead of resin "classification" since resins are first classified by type, and types are further subdivided into grades. We have also provided an example of a resin grade. In the final rule, *grade* means the subdivision of PVC resin that describes it as a unique resin, *i.e.*, the most exact description of a type of resin with no further subdivision. Examples include LMW suspension resins and general purpose suspension resins.

We have revised the definition of *in HAP service*. In the final rule, *in HAP service* means that a process component either contains or contacts a liquid that is at least 5-percent HAP by weight or a gas that is at least 5 percent by volume HAP, as determined according to the provisions of 40 CFR 63.180(d). For the purposes of this definition, the term "in organic HAP service," as used in 40 CFR 63.180(d), means "in HAP service." The provisions of 40 CFR 63.180(d) also specify how to determine that a process component is not in HAP service.

We have revised the definition of *polyvinyl chloride* to clarify that it includes homopolymers and copolymers. In the final rule, *polyvinyl chloride* means either polyvinyl chloride homopolymer or polyvinyl chloride copolymer.

We have revised the definition of *polyvinyl chloride and copolymers production process unit or (PVCPU)* to remove components that are storage tanks or vessels, heat exchange systems, wastewater and wastewater collection and treatment systems, and add instrumentation systems. Multiple PVCPU may be located at the same affected source and share storage tanks, heat exchange systems and process wastewater treatment systems. Therefore this shared equipment has been removed from the definition of a PVCPU and is now included in the definition of the affected source instead of the PVCPU. In the final rule, *polyvinyl chloride and copolymers production process unit or (PVCPU)* means a collection of process components assembled and connected by hard-piping or duct work, used to process raw materials and to manufacture polyvinyl chloride and/or polyvinyl chloride copolymers. A PVCPU includes, but is not limited to, polymerization reactors; resin stripping operations; resin blend tanks; resin centrifuges; resin dryers; resin product separators; recovery devices; reactant and raw material charge vessels and tanks, holding tanks, mixing and weighing tanks; finished resin product storage tanks or storage silos; finished resin product loading operations; connected ducts and piping; equipment including pumps, compressors, agitators, PRD, sampling connection systems, open-ended valves or lines, valves and connectors and instrumentation systems. A PVCPU does not include chemical manufacturing process units, as defined in 40 CFR 63.101, that produce VCM or other raw materials used in the PVC polymerization process.

We have revised the definition of *polyvinyl chloride copolymer* to clarify that polyvinyl chloride copolymers can also be produced using a suspension blending process. In the final rule, *polyvinyl chloride copolymer* means a synthetic thermoplastic polymer that is derived from the simultaneous polymerization of vinyl chloride and another monomer, such as vinyl acetate. Polyvinyl chloride copolymer is produced by different processes, including, but not limited to, suspension, dispersion/emulsion, suspension blending and solution processes.

We have revised the definition of *pressure relief device* to remove the condition that devices actuated either by a pressure of less than or equal to 2.5 pounds per square inch gauge or by a vacuum are not PRD. In the final rule, *pressure relief device* means a safety device used to prevent operating pressures from exceeding the maximum allowable working pressure of the process component. A common PRD is a spring-loaded pressure relief valve.

We have revised the definition of *process vent* to provide consistency with our revised definitions of batch process vent and continuous process vent and miscellaneous vent. In the final rule, *process vent* means a vent stream that is the result of the manifolding of each and all batch process vent, continuous process vent or miscellaneous vent resulting from the affected facility into a closed vent system and into a common header that is routed to a control device. The process vent standards apply at the outlet of the control device. A process vent is either a PVC-only process vent or a PVC-combined process vent.

We have revised the definition of *solution processes* to specify that the process produces a polyvinyl chloride copolymer instead of only a polyvinyl chloride resin. In the final rule, *solution process* means a process for producing polyvinyl chloride copolymer resin that is characterized by the anhydrous formation of the polymer through precipitation. Polymerization occurs in an organic solvent in the presence of an initiator where VCM and co-monomers are soluble in the solvent, but the polymer is not. The PVC copolymer is a granule suspended in the solvent, which then precipitates out of solution. Emulsifiers and suspending agents are not used in the solution process. Copolymer resins produced using the solution process are referred to as solution resins.

At proposal, we defined a surge control vessel as part of any continuous operation. However, based on industry comments, gasholders meet the definition of a surge control vessel although gasholders may receive and introduce material into batch processes in addition to continuous processes. Therefore, we have modified the definition of a surge control vessel to reflect the definition in 40 CFR part 63, subpart H and remove the specification that surge control vessels must be used as part of a continuous operation and introduce material into continuous operations. We have, however, modified the definition from 40 CFR part 63, subpart H, to specify that surge control vessels are used within an affected source (and not solely a process unit) since PVCPU may share gasholders. In the final rule, *surge control vessel* means feed drums, recycle drums and intermediate vessels used as a part of any continuous operation. Surge control vessels are used within an affected source when in-process storage, mixing or management of flow rates or volumes is needed to introduce material into continuous operations. Surge control vessels also include gasholders.

We have revised the definition of *type of resin* to include additional resin types identified by commenters after proposal, specifically blending types of resin. In the final rule, *type of resin* means the broad classification of resin referring to the basic manufacturing process for producing that resin, including, but not limited to, suspension, dispersion/emulsion, suspension blending, bulk and solution processes.

We have revised the definition of *wastewater* to mirror definitions in other chemical sector rules, such as the HON, for consistency as several facilities are currently subject to multiple wastewater provisions. We have also specified what is not considered wastewater. In the final rule, *wastewater* means process wastewater and maintenance wastewater. The following are not considered wastewater for the purposes of this subpart:

(1) Stormwater from segregated sewers;

(2) Water from fire-fighting and deluge systems, including testing of such systems;

(3) Spills;

(4) Water from safety showers;

(5) Samples of a size not greater than reasonably necessary for the method of analysis that is used;

(6) Equipment leaks;

(7) Wastewater drips from procedures such as disconnecting hoses after cleaning lines; and

(8) Noncontact cooling water.

The following definitions have been added to the final rule: *gasholder, hard-piping, heat exchanger exit line, maintenance wastewater, miscellaneous vent, polyvinyl chloride homopolymer, process wastewater, process wastewater treatment system, PVC-combined process vent, PVC-only process vent, suspension blending process, table 10 HAP, total non-vinyl chloride organic HAP* and *wastewater stream.*

We have added a definition for *polyvinyl chloride homopolymers* to distinguish between homopolymers and copolymers. During the comment period, industry provided additional resin data distinguishing homopolymers and copolymers and is based largely on the proposed definition for polyvinyl chloride. For reasons discussion in section V.D of this preamble, we have set limits for five subcategories of resin, including copolymers. Therefore, the new definitions are necessary to distinguish between homopolymers and copolymers. The definitions are based on the information provided in comments. In the final rule, *polyvinyl chloride homopolymer* means a synthetic thermoplastic polymer that is derived from the polymerization of vinyl chloride and has the general chemical structure $(\text{-}H_2CCHCl\text{-})_n$. Polyvinyl chloride homopolymer is typically a white powder or colorless granule. Polyvinyl chloride homopolymers are produced by different processes, including (but not limited to) suspension, dispersion/emulsion, blending and bulk processes.

At proposal, we did not set separate limits for suspension blending resins. During the comment period, industry provided additional resin data regarding suspension blending resins. As described in section V.D of this preamble, we have set limits for five types of resin, including suspension blending. Therefore, a definition to distinguish suspension blending resins from other resin types is necessary. The definition is based on the information provided in comments. In the final rule, *suspension blending process* means a process for producing polyvinyl chloride resin that is similar to the suspension polymerization process, but employs a rate of agitation that is significantly higher than the highest range for non-blending suspension resins. The suspension blending process uses a recipe that creates extremely small resin particles, generally equal to or less than 100 microns in size, with a glassy surface and very little porosity. The suspension blending process concentrates the resins using a centrifuge that is specifically designed to handle these small particles. Polyvinyl chloride resins produced using the suspension blending process are referred to as blending resins and are typically blended with dispersion resins.

At proposal, we did not subcategorize process vents. For the final rule, we are subcategorizing process vents into PVC-only and PVC-combined vents for reasons discussed in section V.D of this preamble. Therefore, it is necessary to distinguish between the two process vent subcategories. In the final rule, *PVC-only process vent* means a process vent that originates from a PVCPU and is not combined with a process vent originating from another source category prior to being controlled or emitted to the atmosphere. In the final rule, *PVC-combined process vent* means a process vent that originates from a PVCPU and is combined with one or more process vents originating from another source category prior to being controlled or emitted to the atmosphere.

At proposal, we did not have information on gasholders and did not propose standards for them. Following proposal, industry provided comment on control options and cost information for gasholders and we have included requirements for gasholders in the final rule. Therefore it was necessary to add a definition for gasholders to the final rule. The definition is based on information provided in comments. In the final rule, *gasholder* means a surge control vessel with a bell that is floating in a vessel filled with water and is used to store gases from the PVC production process prior to being recovered or sent to a process vent control device. The bell rises and lowers as low-pressure gases enter and leave the space beneath the bell and the water provides a seal between the enclosed gas within the floating bell and the ambient air.

At proposal, we did not define *maintenance wastewater,* but instead, required that all wastewater be subject to the same proposed provisions. We received comments from industry contending that quantifying a concentration to establish compliance for maintenance wastewater would be extremely difficult if not impossible because maintenance activities are highly variable. Industry also noted that HAP are minimized in maintenance wastewater by requiring that components meet applicable opening standards before the introduction of water for cleaning. The final rule includes provisions that address process and maintenance wastewater separately; therefore, we have added definitions for *maintenance wastewater* and *process wastewater* to the final rule. The definitions are based on those provided

in the HON, because the wastewater streams are similar and, in some cases, they are co-located. In the final rule, *maintenance wastewater* means wastewater generated by the draining of process fluid from components in the PVCPU into an individual drain system prior to or during maintenance activities. Maintenance wastewater can be generated during planned and unplanned shutdowns and during periods not associated with a shutdown. Examples of activities that can generate maintenance wastewaters include descaling of heat exchanger tubing bundles, hydroblasting PVCPU process components such as polymerization reactors, vessels and heat exchangers, draining of low legs and high point bleeds, draining of pumps into an individual drain system, draining of portions of the PVCPU for repair and water used to wash out process components or equipment after the process components or equipment has already been opened to the atmosphere and has met the requirements of 40 CFR 63.11955. In the final rule, *process wastewater* means water that comes into direct contact with HAP or results from the production or use of any raw material, intermediate product, finished product, by-product or waste product containing HAP, but that has not been discharged untreated as wastewater. Examples are product tank drawdown or feed tank drawdown; water formed during a chemical reaction or used as a reactant; water used to wash impurities from organic products or reactants; water used to cool or quench organic vapor streams through direct contact; water discarded from a control device; and condensed steam from jet ejector systems pulling vacuum on vessels containing organics. Gasholder seal water is not process wastewater until it is removed from the gasholder.

In the final rule, *wastewater stream* means a stream that contains only wastewater as defined in this section.

Also in the final rule, *table 10 HAP* means a HAP compound listed in table 10 of final rule. *Total non-vinyl chloride organic HAP* means, for the purposes of this subpart, the sum of the measured concentrations of each table 10 compound as calculated according to the procedures specified in 40 CFR 63.11960(e) and 40 CFR 63.11980(b).

J. Cost and Emission Impacts

Comment: Three commenters expressed concern that costs for PRD are greatly underestimated. One commenter estimated that retrofitting existing PRD with release indicators will cost $5,000 per PRD. The commenter stated that these costs include the actual measurement device itself, installation labor, wiring back to the control room, input/output cards in distributed control system (DCS) and initial configuration (programming) of the DCS for alarms, logging, etc. The commenter stated that with two facilities each containing over 100 PRD the total cost would be over $1,000,000 to retrofit. Another commenter also cited an estimate of $5,000 if a wireless pressure monitoring device is used, or $10,000 per PRD if a more substantial flow monitoring device is needed. The commenter estimated the cost for its three facilities with 393 total PRD would range from $1,965,000 to $3,930,000 to retrofit. A third commenter estimated a cost of $10,000 to retrofit each PRD, accounting for installation and integration into the process control system. With approximately 200 PRD at a facility, the commenter estimated a total cost of $2,000,000. One commenter also noted that if the EPA is requesting pressure switches between the rupture discs and the safety valves, this is "relatively" easy to accomplish because it would require the instrument, communication wiring, and a small amount of piping. This commenter also requested that the EPA make it clearer whether flow indication or pressure indication is required in the proposed rule. Additionally, one commenter stated that multiple systems for release indication already exist within PVC operations.

One commenter expressed concern about bypass flow indicator costs. The commenter stated that a conservative estimate to install bypass flow indicators is similar to that for flow indication on PRD, approximately $5,000 per open ended line. Considering there are hundreds of such lines, the commenter indicated that installation cost could exceed $1,000,000 per facility.

Response: The EPA maintains that the capital cost estimate of $188,900 and annual cost estimate of $26,900 per facility is appropriate. Although commenters provided cost estimates for particular facilities, costs provided in the comment letters were general in nature, and the commenters did not provide documentation or detailed cost analyses such that the provided estimates could be reviewed. Therefore, we must estimate costs for all facilities using a consistent methodology which is based on data collected by the EPA. We developed our cost estimate for electronic PRD monitoring systems using the *Proposed Amended Rule 1173—Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants,* from the South Coast Air Quality Management District. Other commenters have stated that most PVC plants "typically have rupture discs installed below relief valves that discharge to the atmosphere, and monitor the space between the rupture disc and the PRD for leaks on a routine basis using a local pressure indicator and log this information for safety purposes." The EPA maintains that a facility must use a monitor to indicate an emission release to the atmosphere; the type of indicator is left to the facility.

Comment: Several commenters took issue with the cost estimates related to resin stripping. The commenters stated that current technology will not allow facilities to meet the resin limits and indicated that it will be necessary to develop new technology and the associated costs will be much greater than the current EPA stripped resin cost estimate. One commenter stated that millions of dollars will be required to develop the technology and install equipment. Commenters contended that improvements in PVC resin stripping beyond that which can be achieved to meet new MACT floor HAP concentrations are not feasible due to thermal degradation of PVC resins with elevated heat histories (combination of higher temperatures and residence times). One commenter added that steam is one of many components in the resin stripping process, but it cannot be used as the sole or primary control technique without seriously degrading the resin product. Commenters indicated that some types and grades of resin are sensitive to heat history such as that incurred by steam stripping and that color and heat stability can be negatively impacted by excess heat history. Several commenters disagreed with the EPA's conclusion that PVCPU would only need to use additional steam in existing equipment to strip resin to comply with the proposed vinyl chloride and total HAP emission limits. Commenters also indicated that the effectiveness of certain types of stripping technologies is not increased by the addition of steam above energy balance requirements. Another commenter added that PVC resins, some types and grades more than others, are sensitive to heat such as that incurred by steam stripping. One commenter stated that the EPA offered no substantiation for the claim that more steam in existing equipment would provide for anything more than negligible reductions in vinyl chloride and HAP levels in stripped resin. The commenter added that two of the major

licensors of PVC resin stripping technology have said they would not guarantee new equipment, let alone existing equipment, could meet the proposed limit of 0.48 ppmw of vinyl chloride for all resins. Commenters indicated that for some PVC grades, a significant column retrofit or replacement would be necessary to meet more stringent resin limits.

Response: For the final rule, we revised the methodology used to estimate cost impacts for stripped resin based on the comments and additional cost data provided by commenters. For the proposed rule, costs of affected sources meeting the proposed concentration standards for stripped resins were estimated by calculating the amount of additional steam required to strip vinyl chloride and total HAP to the proposed concentration standards. Based on comments and information provided by commenters, we agree that costing additional steam may not be the appropriate control technique to meet the stripped resin limits. For the final rule, we estimated costs of affected sources demonstrating compliance with the final stripped resin concentration standards by calculating the cost of installing a new resin stripper, based on information provided by commenters. We did not include annual costs other than the amortized capital investment since affected sources must currently pay for the operation and maintenance of their current resin strippers. Additionally, we have revised MACT floor calculations, as discussed in section V.E.2 of this preamble. The revised MACT floor and impacts analyses show that one facility will not be able to meet the final limits. Based on information received during the public comment period, we estimate the one facility not able to meet the final limits will be required to install a new resin stripper with a total capital cost of $10 million and a total incremental annual cost of $944,000 per year.

Comment: Several commenters expressed concern with the costs imposed by wastewater compliance requirements. One commenter contended that requiring monthly sampling for HAP in wastewater will impose undue hardship on facilities when they are required to perform continuous monitoring of stripper operating levels as well. This commenter estimated an additional $65,000 per year from the monthly sampling. Another commenter stated that due to the low wastewater vinyl chloride limit, the cost for controls will be much higher. The commenter added that simply adding steam will be insufficient and that it will be necessary to replace the stripper at a cost of $3,400,000 with annual operating costs of $636,000. One commenter recommended that the HAP control requirements (testing, sampling, etc.) should be removed from the wastewater rule since no emission benefit is achieved.

Response: Similar to our decision for stripped resins in the final rule, we have removed all requirements for continuous parametric monitoring of wastewater strippers. The requirements to conduct periodic sampling for vinyl chloride and total non-vinyl chloride organic HAP are sufficient to assure compliance with the stripped resin limits. We have also established a revised limit for total non-vinyl chloride organic HAP from process wastewater. Monthly sampling and analysis for total non-vinyl chloride organic HAP is necessary to ensure that the limits are being met on a continuous basis. We have also substantially reduced the burden on facilities by only requiring re-analysis of untreated streams once per year to ensure that those streams are below the process wastewater limits and that they do not require treatment. These changes have significantly reduced the burden of the final rule.

K. Economic Impacts

Comment: Several commenters expressed concern with the economic ramifications of the proposed rule to PVC producers and consumers. The commenters stated that the EPA did not adequately quantify the effect to the entire PVC supply chain when considering the rule and that as a result many hardships and changes will occur. Commenters contended that impacts will be cascaded down the supply chain and increase cost of doing business. One commenter encouraged the agency to review and carefully consider these impacts in light of the Obama Administration's Executive Order 13563, *Improving Regulation and Regulatory Review*, which calls for review and revision of regulations that stifle job creation and economic growth.

Commenters argued the PVC MACT will impact a company's competitiveness in the global market, where overseas PVC producers are not subject to such stringent regulations. One commenter expressed concern with the impact on construction of new plants; the proposed PVC rule will pose a significant deterrent to any company that considers citing new or reconstructed PVC manufacturing in the United States causing additional harm to the economy. Several commenters expressed concern that if enacted without significant revision, the PVC rule will result in the closure of several plants in the United States.

One commenter representing the chlor-alkali industry provided an example of how the PVC rule will impact related industries. The commenter stated that as currently proposed compliance by United States PVC manufacturing facilities with the MACT will cause a 4-percent–8-percent reduction in demand in the domestic chlorine market. Based on average industry pending patterns and labor-output ratios, in total, between 3,300 and 6,600 jobs are at risk.

Commenters expressed concern regarding the economic impacts to several industries, including: the wall covering industry, the vinyl flooring industry, resilient flooring operations, pipe applications and the vinyl siding products industry.

Several commenters contended that the PVC rule would result in loss of performance characteristics and cost increases due to discontinuation and substitution of a different quality or type of resin for a previously formulated material, engineering changes, such as retooling or the necessary investment in new or replacement equipment due to the different types or qualities of resin and different formulations, and loss of time as new formulations may take years to develop and refine for their intended application. The commenters contended that over 100 types and grades of PVC resins will be affected, resulting in significant impact on how compounders, converters and fabricators operate, potentially changing product performance or raising costs. Other Two commenters stated that the net cost to consumers in the United States and Canada for the substitution of alternative materials for the PVC-based products that they currently use would be almost $17.7 billion dollars per year, plus an additional $5.6 billion in new investment to manufacture the incremental volume of substitute material and an associated $2.8 billion per year in capital recovery charges (details for numbers are in the document, *The Economic Benefits of Polyvinyl Chloride in the United States and Canada*, released by the American Chemistry Council and The Vinyl Institute in 2008). Several commenters expressed concern that imposing overly stringent requirements on PVC resin manufacturers will significantly increase imports from foreign sources and result in less domestic competition.

Response: The final rule contains several revisions that reduce the annual cost of the final rules by more than 75 percent from proposal ($19.7 million per year at proposal to $4.1 million per

year for the final rules, for major and area sources combined). These revisions are discussed in section VI of this preamble. For the reasons described above, we have revised subcategories and the MACT floor calculation for stripped resins resulting in revised limits for stripped resins. These changes result in stripped resin limits that are achievable by 15 out of 16 sources without installation of additional controls. Based on information received during the public comment period, the EPA estimates the one facility not able to meet the final stripped resin limits for major sources will be required to install a new resin stripper with a total capital cost of $10 million and an incremental annual cost of $944,000 per year. As a result, the final rule does not impose a significant burden on the source category as a whole. The commenters also did not supply any data or analysis to justify their assertions regarding potential plant closures, negative employment impacts, reduction in demand for chlorine, negative effects on the PVC supply chain, possible increases in imports or other economic harm.

Comment: One commenter expressed concern with the lack of consideration given to small businesses. The commenter stated that the EPA's Economic Impact Analysis identified only eight companies affected by the proposed rule. The commenter added that because all eight of these companies have more than 1,500 employees and annual revenues above $2 billion, the EPA certified the proposed rule and declared no significant economic impact on a substantial number of small entities. As such, no regulatory flexibility analysis was prepared by the agency. However, the commenter contended, the EPA did not host any "SBREFA panels" prior to reaching this conclusion, preventing the small business community from providing relevant input on the proposed rule's impacts. The commenter stated that there will be higher costs due to the PVC MACT which could be passed along the supply chain in the form of higher prices to customers, many of whom may be small businesses and less able to absorb regulation-induced price increases. The commenter concluded that the EPA should amend its analysis to investigate the secondary effect of the regulation on small businesses down the supply chain.

Response: The analysis of impacts on small entities called for by the Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA), is to cover small entities directly affected by a rule. The RFA does not require indirect or secondary impacts to be included in a small entity analysis. This is consistent with the EPA's interpretation of the RFA as amended by SBREFA. Only rules that will have a direct significant adverse economic impact on a substantial number of small entities that are subject to the rule require an Initial Regulatory Flexibility Analysis or Final Regulatory Flexibility Analysis (see 5 U.S.C. sections 603–605).

L. Affirmative Defense

Comment: Several commenters opposed the EPA's affirmative defense requirements. One commenter contended it is unlawful and arbitrary because, although the EPA has eliminated its compliance exemption for periods of startup, shutdown and malfunction, the agency's final rule includes an "affirmative defense to penalties that purports to bar courts from imposing any penalties on sources that violate their emission standards during a malfunction and satisfy certain agency created conditions related to preventing malfunctions and controlling malfunction emissions." This commenter contended that in this proposal, the EPA acts outside of its delegated authority to limit civil penalties available in citizen suits or its own enforcement actions, and the proposal will impermissibly chill citizen participation and the ability to win an effective, deterrent remedy in CAA enforcement actions. The commenter added that the affirmative defense would likely be used on a routine basis by polluters seeking to avoid penalties, imposing a technical burden on citizens seeking civil penalties against polluters.

Another commenter opposed incorporating affirmative defense penalties into regulations. The commenter stated that the EPA has discretion to decide what cases to prosecute, to consider settlements and to request civil penalties in a case-by-case manner, as long as it acts consistent with the CAA to protect clean air as its top priority and, thus, the commenter believes that promulgating this affirmative defense will allow polluters to claim that any violation of the standard is due to a malfunction in order to evade the requirements.

Another commenter requested that if affirmative defense is promulgated, the EPA specify the amount of compensatory damages should apply to each malfunction, modify the rule so that affirmative defense cannot be used by a specific facility or company more than once within a set period of time, and require public reporting of malfunctions or emissions exceedances.

Response: The EPA included an affirmative defense in the final rule in an attempt to balance a tension inherent in many types of air regulation to ensure adequate compliance, while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that "limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis." 42 U.S.C. 7602(k) (defining "emission limitation and emission standard"). See generally *Sierra Club* v. *EPA*, 551 F.3d 1019, 1021 (D.C. Cir. 2008). Thus, the EPA is required to ensure that CAA section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief. While "continuous" limitations, on the one hand, are required, there is also caselaw indicating that in many situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), the District of Columbia Circuit acknowledged that in setting standards under CAA section 111, "variant provisions," such as provisions allowing for upsets during startup, shutdown and equipment malfunction "appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force." See also, *Portland Cement Association* v. *Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973). Though intervening caselaw such as *Sierra Club* v. *EPA* and the CAA 1977 amendments calls into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating "upsets beyond the control of the permit holder." *Marathon Oil Co.* v. *EPA*, 564 F.2d 1253, 1272–73 (9th Cir. 1977). But, see, *Weyerhaeuser Co.* v. *Costle*, 590

F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission limitations are "continuous," as required by 42 U.S.C. 7602(k), and account for unplanned upsets and, thus, support the reasonableness of the standard as a whole. The EPA is not adopting commenters' suggestion with respect to compensatory damages or limits on the frequency of use of the affirmative defense. It is not clear that EPA has authority to require the automatic imposition of compensatory damages and even if such authority exists, the EPA does not think automatic imposition of damages is appropriate. Ensuring that malfunctions do not recur can be handled through imposition of appropriate injunctive relief. In addition, the EPA's view is that it would not be appropriate to limit a source's ability to take advantage of the affirmative defense to one time over a specified period of time, such as 10 years, given that the affirmative defense is only available when the source could not have prevented the excess emissions. With respect to commenters' suggested reporting requirements, the reporting requirements in the rule promulgated here already require malfunction reporting and the affirmative defense provisions require that parties choosing to assert the affirmative defense meet additional malfunction reporting requirements. Any such reports submitted to the EPA are publicly available pursuant to CAA section 114.

M. Beyond-the-Floor Analyses

At proposal, we determined that the control technologies that would be needed to achieve the proposed MACT floor levels for process vents are generally the most effective controls available for reducing vinyl chloride, HCl, THC and CDD/CDF and we estimated the costs for those technologies for facilities that did not meet the proposed limits for process vents. Furthermore, at proposal, we did not identify any beyond-the-floor options for process vents. For the final rule, as a beyond-the-floor option for process vents (*i.e.,* PVC-only and PVC-combined process vents), we assessed the costs and emission reductions for existing major source facilities to meet the new source limits for both process vent subcategories by using enhanced vinyl chloride recovery (via an upgraded refrigerated condenser). Based on the resulting analysis of the cost effectiveness, we determined it is not appropriate to go beyond-the-floor for either subcategory of process vents at existing sources. This analysis is discussed in the memorandum, *Revised Beyond-the-Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category.*

For stripped resin at existing and new major sources, we analyzed the same beyond-the-floor option as at proposal, and determined it was not appropriate to go beyond-the-floor for stripped resin at existing and new major sources considering the cost and emission reductions of this option.

For equipment leaks, we analyzed a beyond-the-floor option at existing sources of complying with 40 CFR part 63, subpart UU level 2, instead of the MACT floor level of control, compliance with 40 CFR part 61, subpart V. Based on the results of the analysis, which are presented in Tables 16 and 18 of this preamble, we determined that it is appropriate that MACT for equipment leaks at existing and new major sources require compliance with subpart UU level 2, considering the cost and emission reductions of this option. The MACT floor level of control for new sources, compliance with subpart UU level 2, was identified as the most effective control of emissions from equipment leaks. Therefore, no beyond-the-floor HAP emission reduction approaches were identified for equipment leaks at new major sources. This analysis is discussed in sections VI.A and VI.B of this preamble and in the memorandum, *Revised Beyond-the-Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category.*

For heat exchange systems, we determined that the final leak action level and monitoring interval are generally the most effective LDAR program to control emissions from heat exchange systems. Therefore, no beyond-the-floor options were identified for heat exchange systems at existing or new major sources.

At proposal and for the final rule, we determined it is appropriate for storage vessels at existing and new major sources meeting specific vapor pressure and storage capacity parameters specified in 40 CFR part 60, subpart Kb to comply with the control requirements of 40 CFR part 63, subpart WW as a beyond-the-floor control considering cost and emission reductions. This analysis is discussed in sections VI.A and VI.B of this preamble and in the memorandum, *Revised Beyond-the-Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category.*

At proposal, we analyzed a beyond-the-floor option for wastewater of treating streams with HAP concentration greater than 1,000 ppmw (of 40 CFR part 63, subpart G, Table 9 HAP), and annual average flow rates greater than 10 liters per minute. In the final rule, we determined the MACT floor level of control for wastewater to includes concentration limits for total non-vinyl chloride organic HAP. Consequently, we analyzed a different beyond-the-floor options for wastewater, requiring all currently uncontrolled process wastewater (*e.g.,* wastewater from scrubbers and heat exchange systems) to be conveyed to, and treated by, a wastewater stripping unit. Based on the results of this analysis, we determined it is not appropriate to go beyond-the-floor for wastewater at existing and new major sources considering the cost and emission reductions of this option. This analysis is discussed in the memorandum, *Revised Beyond-the-Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category.*

At proposal, we did not identify any beyond-the-floor options for gasholders; however, we did solicit comments on control options for gasholders. Based on the information provided in comments, for the final rule, we analyzed a beyond-the-floor option of minimizing fugitive emissions by requiring the use of floating objects on the surface of the water seal at existing and new sources. Based on the results of the analysis, which are presented in Tables 16 and 18 of this preamble, we determined that it is appropriate to require gasholders at existing and new major sources reduce their fugitive emissions by using floating objects on the surface of the water seal as a beyond-the-floor control, considering cost and emission reductions. This analysis is discussed in the memorandum, *Revised Beyond-the-Floor Analysis for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category.*

VI. Impacts of the Final PVC Rules

The impacts presented in this section include the impacts for PVC production facilities to comply with the final rules, and with the requirements of other subparts referenced by the final rules.

A. What are the air impacts?

We have estimated the potential emission reductions that are expected to be realized through implementation of the final rules. Table 18 of this preamble summarizes the emission reductions estimated for existing major sources. The table shows the emission reductions for each pollutant and emission point. Table 18 of this preamble also summarizes the emission

reductions for the beyond-the-floor options selected for existing major sources (*i.e.*, control of equipment leaks, storage vessels and gasholders). The major source analysis is documented in the memorandum, *Revised Costs and Emission Reductions for Major Sources in the Polyvinyl Chloride and Copolymers (PVC) Production Source Category*. Table 19 of this preamble summarizes the emission reductions estimated for existing area sources complying with GACT. The area source analysis is documented in the memorandum, *Generally Achievable Control Technology (GACT) Analysis for Area Sources in the Polyvinyl Chloride and Copolymers (PVC) Production Source Category*. Both memoranda are available in the docket. We do not project any new major or area sources to be constructed in the 5 years following promulgation of the final rules; no emission reductions were calculated for new sources. The memoranda document emission reductions associated with model major and area sources complying with the new source requirements.

TABLE 18—EMISSION REDUCTIONS OF THE FINAL PVC AND COPOLYMERS PRODUCTION STANDARDS FOR MAJOR SOURCES

Emission point	Pollutant emission reductions (tpy)			
	Vinyl chloride	Total HAP	CDD/CDF (TEQ)	HCl
Major sources MACT floor				
Process vents[a]	0.102	1.93	0.017 g/yr	21.4
Stripped resins	7.58	7.58	0	0
Wastewater	0	0	0	0
Equipment leaks	0	0	0	0
Storage vessels	0	0	0	0
Other emission sources	0	0	0	0
Heat exchange systems	101	101	0	0
Major sources beyond the floor				
Equipment leaks	0	85.0	0	0
Storage vessels	0	0	0	0
Other emission sources-gasholders	22.0	22.0	0	0
Major Source total	130	217	0.017 g/yr	21.4

[a] Emission reductions for process vents are stated as total organic HAP; this value does not include HCl or chlorine reductions.

TABLE 19—EMISSION REDUCTIONS OF THE FINAL PVC AND COPOLYMERS PRODUCTION STANDARDS FOR AREA SOURCES

Emission point	Vinyl chloride (tpy)	Dioxin/furan (g/yr)	Total HAP (tpy)
Process vents	0	0	0
Heat exchange systems	15.1	0	15.1
Stripped resins	0	0	0
Wastewater	0	0	0
Equipment leaks	0	0	9.29
Other emission sources	0	0	0

We estimated emission reductions of the final rule for each emission point. For all emission points, we first calculated emissions at the current level of control for each facility (referred to as the baseline level of control), and at the MACT level of control selected for major sources and the GACT level of control selected for area sources. We calculated emission reductions as the difference between the final level and baseline.

Major Sources

For process vents at major sources, we calculated baseline emissions from the measured HAP concentrations at the outlet of the control devices, and HAP emissions using the final emission limits, in combination with the vent stream flow rates measured during emission tests.

For stripped resins at major sources, we calculated emissions assuming that all the HAP remaining in the resin would eventually be emitted from processes downstream of the resin stripper. This assumption results in a calculation of the potential emissions at the baseline stripped resin concentration levels, and final MACT concentration levels. Emissions were calculated from the HAP concentration in the stripped resin, and the resin production rate.

For wastewater at major sources, we estimated the emissions from the HAP concentration in the uncontrolled wastewater streams, the maintenance wastewater streams, and in the controlled wastewater streams, and the wastewater flow rates or generation rates.

For equipment leaks at major sources, we estimated emissions for the baseline LDAR program in use at each facility, and the final equipment leaks requirements using model equipment counts, average emission factors for leaking equipment and control efficiencies for LDAR programs developed as part of the technology review required by section 112(d)(6) of the CAA (see section V.H of this preamble for additional detail). Model equipment counts were used because actual equipment counts were not

collected as part of our August 21, 2009, CAA section 114 survey and testing request sent to the PVC industry. The survey requested information only on regulatory LDAR programs currently in place at each facility, and the costs for the facility to conduct the LDAR program.

For other emission sources, we estimated baseline emissions from gasholders using information provided by industry during the comment period. We estimated the emission reductions associated with installing floating objects on gasholder water seals to reduce emissions of vinyl chloride from those seals, as a beyond the floor option, based on additional information provided by the PVC industry after the comment period. We calculated emissions from reactor openings from information provided in responses to our August 21, 2009, CAA section 114 survey and testing request provided by affected sources.

We calculated emissions from heat exchange systems based on emissions information provided in the CAA section 114 survey responses provided by affected sources. Emission reductions from heat exchange systems were calculated assuming that, once the LDAR program was in effect, emissions would be eliminated due to the low leak action level that is being finalized.

Area Sources

For process vents, we calculated emissions from the concentration of HAP in the vent stream and the vent gas flow rates measured during emission tests. For process vents in the PVC-only subcategory, we calculated baseline emissions for the one area source in the subcategory from the measured HAP concentrations at the outlet of the control device. We did not select an option more stringent than the current emission level; therefore, there were no emission reductions calculated. For process vents in the PVC-combined subcategory, we calculated baseline emissions for the one area source in the subcategory from the measured HAP concentrations at the outlet of the control. Since the existing PVC-combined area source currently meets the GACT standards, we did not calculate a reduction of HAP emissions associated with meeting the GACT emission limits.

For stripped resins, emissions were calculated from the HAP concentration in the stripped resin, and the resin production rate. For the one existing area source in the suspension subcategory, we calculated emissions assuming that all the HAP remaining in the resin would eventually be emitted from processes downstream of the resin stripper. This assumption results in a calculation of the potential emissions at the stripped resin concentration levels the affected is currently achieving. Since the existing PVC area source in the suspension resin subcategory currently meets the GACT standard, no emission reductions were calculated. For the one existing area source in the bulk resins subcategory, we estimated emissions downstream of the resin stripper using emission rates submitted by the facility since resin produced by the bulk process does not go through downstream drying processes since the resin is in solid form after the polymerization process.

For wastewater at existing area sources, we estimated the emissions from the HAP concentration in the uncontrolled wastewater streams, the maintenance wastewater streams, and in the controlled wastewater streams, and the wastewater flow rates or generation rates.

For equipment leaks at existing area sources, we estimated emissions for the LDAR program in use at both area sources and emissions associated with complying with the GACT option. Emissions were calculated using a combination of facility provided and model equipment counts, average emission factors for leaking equipment and control efficiencies for LDAR programs developed as part of the technology review required by section 112(d)(6) of the CAA (see section V.H of this preamble for additional detail). Model equipment counts were used for equipment types for which counts were not provided by the affected sources. The CAA section 114 survey requested information only on regulatory LDAR programs currently in place at each facility, and the costs for the facility to conduct the LDAR program; however, one facility provided some, but not all equipment counts for which emissions were estimated.

For other emission sources, we calculated emissions from reactor openings from information provided in CAA section 114 survey responses provided by affected sources. The existing PVC area sources currently do not operate gasholders; therefore no emissions from gasholders were calculated for area sources.

We calculated emissions from heat exchange systems based on emissions information provided in the CAA section 114 survey responses provided by affected sources. Emission reductions from heat exchange systems were calculated assuming that, once the LDAR program was in effect, emissions would be eliminated due to the low leak action level that is being finalized.

B. What are the cost impacts?

We have estimated compliance costs for all existing sources to meet the sampling and testing requirements, add the necessary controls, monitoring devices, recordkeeping and reporting procedures to comply with the final rules. Based on this analysis, we anticipate an overall total initial investment of $17.6 million for major sources and $486,000 for area sources. We anticipate an associated total annual cost of $3.94 million for major sources and $167,000 for area sources (using a discount rate of 7 percent), in 2010 dollars, as shown in Table 20 and Table 21 of this preamble. We do not anticipate the construction of any new PVCPU in the next 5 years and, therefore, there are no new source cost impacts. Estimated impacts of the new area source requirements for a model facility are presented in the memoranda, *Costs and Emission Reductions of the MACT Floor Level of Control for the Promulgated Polyvinyl Chloride and Copolymers (PVC) Production Source Category and Cost and Emission Reductions of the Area Source Level of Control for the Promulgated Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* which are in the PVC docket.

TABLE 20—COST IMPACTS OF THE FINAL PVC AND COPOLYMERS PRODUCTION STANDARDS FOR EXISTING MAJOR SOURCES

Emission point	Total initial cost (million 2010$) [a]	Total annual cost (million 2010$/yr) [b]
Major sources MACT floor		
Process vents	3.38	1.72
Stripped resins	10.1	1.13
Wastewater	0.075	0.165
Equipment leaks	2.87	0.469
Storage vessels	0.0165	0.0233
Other emission sources	0.0165	0.0233
Heat exchange systems	0.0466	0.152
Major sources beyond the floor		
Equipment leaks	1.02	0.238
Storage vessels	0	0
Other emission sources—gasholders	0.0750	0.0222
Major source total	17.6	3.94

[a] Total initial costs for facilities include the capital cost of control equipment, testing and monitoring, recordkeeping and reporting.
[b] Total annual costs include: Annualized capital costs, annual cost to operate control equipment, testing and monitoring costs, recordkeeping and reporting costs, and repair costs.

TABLE 21—COST IMPACTS OF THE FINAL PVC AND COPOLYMERS PRODUCTION STANDARDS FOR EXISTING PVC AREA SOURCES

Emission point	Total initial cost (million$)	Total annual cost (million$)	Cost effectiveness ($/ton)
Process vents	0.0963a	0.0218b	(c)
Heat exchange systems	0.00743	0.0255	1,139
Resins	0.00864	0.0212	(c)
Wastewater	0.00743	0.00198	(c)
Equipment leaksd	0.360	0.0725	7,807
Other emission sources	0.00220	0.00311	(c)
Storage vessels	0.00220	0.00311	(c)
Area source total	0.484	0.167	(c)

[a] Total initial cost for process vents includes initial recordkeeping and reporting costs (which include year 1 annual costs) and initial process vent testing.
[b] Total annual costs for process vents include process vent testing and annual recordkeeping and reporting (starting in year 2). Process vent testing is required every 5 years following the initial test; therefore, annual testing costs have been divided by 5 to distribute costs evenly across the 5-year period.
[c] Standard does not result in emission reductions; therefore, a cost effectiveness is not applicable.
[d] Total initial costs for equipment leaks include capital costs associated with complying with 40 CFR part 63, subpart UU, the cost of an electronic PRD monitoring system and the initial recordkeeping and reporting requirements. Annual costs include operation of the PRD monitoring system, complying with subpart UU and annual recordkeeping and reporting costs. Emissions and reductions of VOC, volatile hazardous air pollutants (VHAP) and organic HAP, categorized as total HAP. Emissions, reductions and associated costs referenced from memorandum—Cindy Hancy, RTI, to Jodi Howard, EPA/OAQPS, dated November 10, 2011, subject: *Technology Review for Equipment Leaks* (draft format), which is available in the docket. Baseline emissions, reductions and costs are adjusted based on equipment counts provided by CertainTeed.

Major Sources

For major sources, we calculated costs to meet the final level of control for each emission point. For process vents, we estimated costs to meet the final level of control for PVCPU that do not currently meet the final emission limit, based on reported data. For such PVCPU that currently use thermal oxidizers in combination with acid-gas scrubbers, we estimate the cost of compliance through the use of enhanced vinyl chloride recovery using a refrigerated condenser to reduce the quantity of vinyl chloride combusted to meet the vinyl chloride, HCl, CDD/CDF and THC. For PVCPU that currently use an absorber for vinyl chloride recovery, cost calculations are based on routing the vent gas from the absorber to a refrigerated condenser for enhanced organic HAP recovery. Costs calculations also include capital and annual costs for testing and monitoring of vinyl chloride, HCl, THC and CDD/CDF.

For PVCPU not currently meeting the final stripped resin limits, costs to meet the final level of control are based on industry estimates for a new resin stripper resulting in greater removal of vinyl chloride and total HAP from the resin. Testing and monitoring costs are also included in the costs to meet the final level of control. All PVCPU are expected to meet the final wastewater stripper outlet concentration limit. Therefore, initial and annual costs consist of additional testing and monitoring required to demonstrate compliance with the final emission standards.

For equipment leaks, cost estimates previously developed by the EPA were applied to each PVCPU that did not

already meet the final level of control (*i.e.*, 40 CFR part 63, subpart UU). The cost estimates include additional capital and annual cost associated with facilities switching from compliance with 40 CFR part 61, subpart V to subpart UU. We estimated additional capital and annual costs for an electronic PRD indicator, based on data collected for other EPA projects.

For other emission sources, we calculated costs for complying with the final, beyond-the-floor, level of control for gasholders. Capital cost estimates were based on data provided by industry at the request of the EPA following the comment period. Annual cost estimates were based on standard factors for costs such as amortization, maintenance, taxes and administration.

We calculated costs for complying with the final level for heat exchange systems, based on information collected for other EPA projects.

The analysis is documented in the memorandum, *Revised Costs and Emission Reductions for Major Sources in the Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* and is available in the docket.

Area Sources

For existing area sources, we calculated costs to meet the final level of control for each emission point. For each emission point, we estimated costs of the major source testing, monitoring and recordkeeping requirements.

For process vents in the PVC-only and PVC-combined subcategories, we did not select an option more stringent than the current emission level; therefore, there were no additional costs calculated.

For the one existing area source in the suspension subcategory and the one existing area source in the bulk resins subcategory, we did not calculate any additional costs since both facilities meet the promulgated GACT standards.

For wastewater at existing area sources, we did not estimate any additional costs since both facilities meet the promulgated GACT standards.

For other emission sources, we did not estimate any additional costs since neither of the existing PVC area sources operate a gasholder.

For equipment leaks, cost estimates previously developed by the EPA were applied to the existing area source PVCPU. The cost estimates include additional capital and annual cost associated with the facility switching from compliance with 40 CFR part 61, subpart V to 40 CFR part 63, subpart UU. We estimated additional capital and annual costs for a PRD, based on data collected for other EPA projects.

We calculated costs for complying with the final level of control for heat exchange systems, based on information collected for other EPA projects. The analysis is documented in the memorandum, *Generally Achievable Control Technology (GACT) Analysis for Area Sources in the Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* and is available in the PVC docket.

C. What are the non-air quality health, environmental and energy impacts?

Major Sources

We anticipate major affected sources will need to apply additional controls to meet the final emission limits. The energy impacts associated with meeting the final emission limits would consist primarily of additional electricity needs to run added or improved air pollution control devices. By our estimate, we anticipate that an additional 5,300 megawatt-hours per year would be required for the additional and improved control devices.

We anticipate secondary air impacts from major sources adding controls to meet the standards. The combustion of fuel needed to generate additional electricity would yield slight increases in nitrogen oxide (NO_X) and sulfur dioxide (SO_2) emissions. Since NO_X and SO_2 emissions and electric generating units are covered by capped emissions trading programs, we do not estimate an increase in secondary air impacts for these pollutants for this rule from additional electricity demand. The analyses are documented in the memorandum, *Revised Secondary Impacts for the Polyvinyl Chloride and Copolymers (PVC) Production Source Category,* available in the docket.

Area Sources

We do not anticipate the area affected sources will need to apply any additional controls with additional electricity or fuel requirements associated with meeting the final emission limits. Therefore, we have not estimated any additional secondary electricity generation of air impacts for area sources.

D. What are the economic impacts of the final standards?

We performed an economic impact analysis for PVC consumers and producers nationally, using the annual compliance costs estimated for this final rule. The impacts to producers affected by this final rule are annualized costs of less than 0.7 percent of their revenues, using the most current year available for revenue data. Demand and supply of PVC product is inelastic according to data included in the Economic Impact Analysis. Based on this information, one can conclude that demand will respond less than 1 to 1 with a change in output price, and that supply is inelastic (*i.e.*, will respond less than 1 to 1) with a change in output price. Hence, based on these results and data, the overall economic impact of this final rule on the affected industries and their consumers should be low. For more information, please refer to the *Economic Impact Analysis for the Polyvinyl Chloride and Copolymer NESHAP* that is in the docket (EPA–HQ–OAR–2002–0037).

VII. Statutory and Executive Order Reviews

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

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action" because it raises novel legal or policy issues. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared an analysis of the potential costs and emissions impacts associated with this action. This analysis is contained in *Cost and Impacts of the PVC and Copolymers Final Standard,* in Docket ID No. EPA–HQ–OAR–2002–0037. A copy of the analysis is available in the docket for this action and the analysis is briefly summarized in section VI.B of this preamble.

B. Paperwork Reduction Act

The information collection requirements in this final rule 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 the OMB approves them.

The information requirements are based on notification, recordkeeping and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA

pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

The final rule requires maintenance inspections of the control devices, and some notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance. The information collection activities in this information collection request (ICR) include the following: Performance tests, wastewater sampling, resin sampling, LDAR monitoring, heat exchanger monitoring, PRD monitoring, operating parameter monitoring, preparation of a site-specific monitoring plan, monitoring and inspection, one-time and periodic reports and the maintenance of records. Some information collection activities included in the NESHAP may occur within the first 3 years, and are presented in this burden estimate, but may not occur until 4 or 5 years following promulgation of the final rule for some affected sources. To be conservative in our estimate, the burden for these items is included in this ICR. An initial notification is required to notify the Administrator of the applicability of this subpart, and to identify storage vessels, process vents, stripped resin, equipment leaks, wastewater, heat exchange systems and other emission sources subject to this subpart. A notification of performance test must be submitted, and a site-specific test plan written for the performance test, along with a monitoring plan. Following the initial performance test, the owner or operator must submit a notification of compliance status that documents the performance test and the values for the operating parameters. A periodic report submitted every 6 months documents the values for the operating parameters and deviations; a notification of inspection of vessels and related inspection records; leaking and monitoring information for equipment leaks; and leaking and monitoring data for heat exchangers, if greater than leak definition. Owners or operators of PVC facilities are required to keep records of certain parameters and information for a period of 5 years. The annual testing, annual monitoring, reporting and recordkeeping burden for this collection for major sources (averaged over the first 3 years after the effective date of the standards) is estimated to be $1.8 million. This includes 3,200 labor hours per year at a total labor cost of $0.3 million per year, and total non-labor capital costs of $2.8 million per year. The annual testing, annual monitoring, reporting and recordkeeping burden for this collection for area sources (averaged over the first 3 years after the effective date of the standards) is estimated to be $323,000. This includes 425 labor hours per year at a total labor cost of $41,000 per year, and total non-labor capital costs of $129,000 per year. These estimates include initial and annual performance tests, conducting and documenting semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications and recordkeeping. Monitoring and testing cost were also included in the cost estimates presented in the control costs impacts estimates in section VI.B of this preamble. The total burden for the federal government (averaged over the first 3 years after the effective date of the standard) for major sources is estimated to be 809 hours per year, at a total labor cost of $37,281 per year. The total burden for the federal government (averaged over the first 3 years after the effective date of the standard) for area sources is estimated to be 160 hours per year, at a total labor cost of $7,324 per year. Burden is defined at 5 CFR 1320.3(b).

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 63, subparts DDDDDD and HHHHHHH. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (*e.g.*, sudden, infrequent, not reasonably preventable and not caused by poor maintenance or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense. The EPA considered whether there might be any burden associated with the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense. While recognizing that any such burdens are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. The PVC industry is currently required to comply with the part 61 NESHAP requirement for releases from pressure relief valves and reactor manual vent valves, which does not allow a discharge into the atmosphere from these valves, except during an emergency. An emergency discharge means a "discharge which could not have been avoided by taking measures to prevent the discharge." The owners or operators must, within 10 days of any release from a pressure relief valve or a reactor manual vent valve, submit a report to the Administrator. The report must include the "nature and cause of discharge, the date and time of the discharge, the approximate total vinyl chloride loss during the discharge, the method used for determining the vinyl chloride loss, the action that was taken to prevent the discharge, and measures adopted to prevent future discharges." The costs for these reports are already accounted for in the ICR burden estimate. Therefore, the EPA estimates that there would be no additional costs for sources that choose to take advantage of the affirmative defense for malfunctions since it is already required for compliance with the rule. However, there may be other malfunctions that are not currently regulated under the part 61 NESHAP that might prompt a source to take advantage of an affirmative defense.

To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source (for those not already regulated under the part 61 NESHAP), the EPA is including in the ICR the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports and records, including the root cause analysis, totals $3,141 and is based on the time and effort required of a source to review relevant data, interview plant employees and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information

unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When 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 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 final rule on small entities, small entity is defined as: (1) A small business, as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated, and is not dominant in its field.

After considering the economic impacts of this 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 industry in which the affected entities are in is NAICS 325211 (Polyvinyl chemical resins manufacturing). The Small Business Administration small business size definition for this industry is 750 employees or less for parent entities. This final rule will not impose any requirements on small entities. To the EPA's knowledge, there are no small entities subject to the final rule.

D. Unfunded Mandates Reform Act (UMRA)

This 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. The total annualized cost of this rule is estimated to be no more than $4.1 million (2010$) in any one year. Thus, this rule is not subject to the requirements of sections 202 or 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA, because it contains no regulatory requirements that might significantly or uniquely affect small governments. This rule impacts only PVC production facilities and, thus, does not impact small governments uniquely or significantly.

E. Executive Order 13132: Federalism

The 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. The final rule imposes requirements on owners and operators of specified major and area sources, and not on state or local governments. There are no PVC production facilities owned or operated by state or local governments. Thus, Executive Order 13132 does not apply to this action.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). The final rule imposes requirements on owners and operators of specified area sources, and not tribal governments. There are no PVC production facilities owned or operated by Indian tribal governments. Thus, Executive Order 13175 does not apply to this action.

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

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

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

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. The EPA estimates that the requirements in this final action would cause most PVCPU to modify existing air pollution control devices (e.g., increase the horsepower of their wet scrubbers) or install and operate new control devices, resulting in approximately 92,000 megawatt-hours per year of additional electricity being used.

Given the negligible change in energy consumption resulting from this final action, the EPA does not expect any significant price increase for any energy type. The cost of energy distribution should not be affected at all by this final action since the action would not affect energy distribution facilities. We also expect that any impacts on the import of foreign energy supplies, or any other adverse outcomes that may occur with regards to energy supplies, would not be significant. We, therefore, conclude that if there were to be any adverse energy effects associated with this final action, they would be minimal.

I. National Technology Transfer and Advancement Act

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

This final rulemaking involves technical standards. The EPA proposes to use ANSI/ASME PTC 19.10–1981, *Flue and Exhaust Gas Analyses,* as an acceptable alternative to EPA Method 3B. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990.

No applicable VCS were identified for EPA Methods 1A, 2A, 2D, 2F, 2G, 21, 107, RCRA SW–846, PS–8, PS–9 and the TCEQ Modified El Paso Method.

During the search, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that were similar to the EPA's reference method, the EPA ordered a copy of the standard and reviewed it as a potential equivalent method. All potential standards were reviewed to determine the practicality of the VCS for this rule. This review requires significant method validation data that meet the requirements of EPA Method 301 for accepting alternative

methods or scientific, engineering and policy equivalence to procedures in the EPA reference methods. The EPA may reconsider determinations of impracticality when additional information is available for particular VCS.

The search identified 17 other VCS that were potentially applicable for this rule in lieu of the EPA reference methods. After reviewing the available standards, the EPA determined that 17 candidate VCS (ASTM D3154–00 (2006), ASTM D3464–96 (2007), ASTM D3796–90 (2004), ISO 10780:1994, ASME B133.9–1994 (2001), ANSI/ ASME PTC 19.10–1981 Part 10, ISO 10396:1993 (2007), ISO 12039:2001, ASTM D5835–95 (2007), ASTM D6522–00 (2005), CAN/CSA Z223.2–M86 (1999), NIOSH Method 2010, Amines, Aliphatic, ASTM D6060–96 (2001), EN 1948–3 (1996), EN 1911–1.2.3 (1998), ASTM D6735–01, ASTM D4855–97 (2002)) identified for measuring emissions of pollutants or their surrogates subject to emission standards in the rule would not be practical due to lack of equivalency, documentation, validation data and other important technical and policy considerations.

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

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

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations, because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

An analysis of demographic data shows that the average percentage of minorities, percentages of the population below the poverty level, and the percentages of the population 17 years old and younger, in close proximity to the sources, are similar to the national averages, with percentage differences of 3, 1.8 and 1.7, respectively, at the 3-mile radius of concern. These differences in the absolute number of percentage points from the national average indicate a 9.4-percent, 14.4-percent and 6.6-percent over-representation of minority populations, populations below the poverty level and the percentages of the population 17 years old and younger, respectively.

In determining the aggregate demographic makeup of the communities near affected sources, the EPA used census data at the block group level to identify demographics of the populations considered to be living near affected sources, such that they have notable exposures to current emissions from these sources. In this approach, the EPA reviewed the distributions of different socio-demographic groups in the locations of the expected emission reductions from this rule. The review identified those census block groups with centroids within a circular distance of a 0.5, 3 and 5 miles of affected sources, and determined the demographic and socio-economic composition (e.g., race, income, education, etc.) of these census block groups. The radius of 3 miles (or approximately 5 kilometers) has been used in other demographic analyses focused on areas around potential sources.[5][6][7][8] There was only one census block group with its centroid within 0.5 miles of any source affected by the final rule. The EPA's demographic analysis has shown that these areas, in aggregate, have similar proportions of American Indians, African-Americans, Hispanics and "Other and Multi-racial" populations to the national average. The analysis also showed that these areas, in aggregate, had similar proportions of families with incomes below the poverty level as the national average, and similar populations of children 17 years of age and younger.[9]

The EPA developed a communication and outreach strategy to ensure that interested communities have access to this final rule, are aware of its content, and had an opportunity to comment during the comment period. The EPA also ensured that interested communities had an opportunity to comment during the comment period. During the comment period, the EPA publicized the rulemaking via environmental justice newsletters, Tribal newsletters, environmental justice listservs and the Internet, including the EPA Office of Policy Rulemaking Gateway Web site (*http://yosemite.epa.gov/opei/RuleGate.nsf/*). The EPA will also conduct targeted outreach to environmental justice communities, as appropriate. Outreach activities may include providing general rulemaking fact sheets (*e.g.,* why is this important for my community) for environmental justice community groups, and conducting conference calls with interested communities. In addition, state and federal permitting requirements will provide state and local governments, and members of affected communities the opportunity to provide comments on the permit conditions associated with permitting the sources affected by the final rule.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.,* as added by the SBREFA of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the United States Senate, the United States House of Representatives and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective April 17, 2012.

List of Subjects in 40 CFR Part 63

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

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[5] U.S. GAO (Government Accountability Office). *Demographics of People Living Near Waste Facilities*. Washington DC: Government Printing Office; 1995.

[6] Mohai P, Saha R. *Reassessing Racial and Socioeconomic Disparities in Environmental Justice Research*. Demography. 2006;43(2): 383–399.

[7] Mennis J. *Using Geographic Information Systems to Create and Analyze Statistical Surfaces of Populations and Risk for Environmental Justice Analysis*. *Social Science Quarterly*, 2002;83(1):281–297.

[8] Bullard RD, Mohai P, Wright B, Saha R, *et al. Toxic Waste and Race at Twenty 1987–2007*. United Church of Christ. March, 2007.

[9] The results of the demographic analysis are presented in *Review of Environmental Justice Impacts: Polyvinyl Chloride*, September 2010, a copy of which is available in the docket.

Dated: February 13, 2012.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations, is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

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

Subpart A—[Amended]

■ 2. Section 63.14 is amended by:
■ a. Adding new paragraph (b)(45).
■ b. Revising paragraphs (b)(8), (b)(28), and (b)(54).
■ c. Revising paragraph (c)(3).
■ d. Revising paragraph (i)(1).
■ e. Revising paragraph (n)(1).
■ f. Adding paragraphs (p)(8) through (p)(11) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) * * *

(8) ASTM D2879–83, Standard Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1983, IBR approved for §§ 63.111, 63.2406, and 63.12005.

* * * * *

(28) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectometry, approved 2004, IBR approved for §§ 60.485, 60.485a, 63.772, 63.2351, 63.2354, and table 8 to subpart HHHHHHH of this part.

* * * * *

(45) ASTM D2879–96, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1996, IBR approved for §§ 63.111, 63.2406, and 63.12005.

* * * * *

(54) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved 2003, IBR approved for § 63.1349, table 4 to subpart DDDD of this part, and table 8 to subpart HHHHHHH of this part.

* * * * *

(c) * * *

(3) API Manual of Petroleum Measurement Specifications (MPMS) Chapter 19.2 (API MPMS 19.2), Evaporative Loss From Floating-Roof Tanks (formerly API Publications 2517 and 2519), First Edition, April 1997, IBR approved for §§ 63.1251 and 63.12005.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus]," IBR approved for §§ 63.309, 63.865, 63.3166, 63.3360, 63.3545, 63.3555, 63.4166, 63.4362, 63.4766, 63.4965, 63.5160, 63.9307, 63.9323, 63.11148, 63.11155, 63.11162, 63.11163, 63.11410, 63.11551, 63.11945, table 5 to subpart DDDDD of this part, table 1 to subpart ZZZZZ of this part, table 4 to subpart JJJJJJ of this part, and table 5 to subpart UUUUU of this part.

* * * * *

(n) * * *

(1) "Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources" (Modified El Paso Method), Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, January 31, 2003, IBR approved for §§ 63.654 and 63.11920.

* * * * *

(p) * * *

(8) Method 8015C (SW–846–8015C), Nonhalogenated Organics by Gas Chromatography, Revision 3, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for §§ 63.11960, 63.11980, and table 10 to subpart HHHHHHH of this part.

(9) Method 8260B (SW–846–8260B), Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), Revision 2, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for §§ 63.11960, 63.11980, and table 10 to subpart HHHHHHH of this part.

(10) Method 8270D (SW–846–8270D), Semivolatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), Revision 4, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for §§ 63.11960, 63.11980, and table 10 to subpart HHHHHHH of this part.

(11) Method 8315A (SW–846–8315A), Determination of Carbonyl Compounds by High Performance Liquid Chromatography (HPLC), Revision 1, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for §§ 63.11960, 63.11980, and table 10 to subpart HHHHHHH of this part.

* * * * *

Subpart DDDDDD—[Amended]

■ 3. Section 63.11140 is revised to read as follows:

§ 63.11140 Am I subject to this subpart?

(a) On or before April 17, 2012, you are subject to this subpart if you own or operate a plant specified in § 61.61(c) of this chapter that produces polyvinyl chloride (PVC) or copolymers and is an area source of hazardous air pollutant (HAP) emissions. After April 17, 2012, you are subject to the requirements in this subpart if you own or operate one or more polyvinyl chloride and copolymers process units (PVCPU), as defined in § 63.12005, that are located at, or are part of, an area source of HAP.

(b) On or before April 17, 2012, this subpart applies to each new or existing affected source. The affected source is the collection of all equipment and activities in vinyl chloride service necessary to produce PVC and copolymers. An affected source does not include portions of your PVC and copolymers production operations that meet the criteria in § 61.60(b) or (c) of this chapter. After April 17, 2012, this subpart applies to each polyvinyl chloride and copolymers production affected source. The polyvinyl chloride and copolymers production affected source is the facility-wide collection of PVCPU, storage vessels, heat exchange systems, surge control vessels, and wastewater and process wastewater treatment systems that are associated with producing polyvinyl chloride and copolymers.

(1) An affected source is existing if you commenced construction or reconstruction of the affected source before October 6, 2006.

(i) You must meet the applicable requirements of §§ 63.11142(a), 63.11143(a) and (b), 63.11144(a) and 63.11145 for existing affected sources.

(ii) You must achieve compliance by the date specified in § 63.11141(a).

(iii) You must meet the applicable requirements of §§ 63.11142(b) through (f), 63.11143(c), 63.11144(b) and 63.11145 for existing affected sources by the compliance date specified in § 63.11141(c), after which time you are no longer subject to the requirements listed in paragraphs (b)(1)(i) and (ii) of this section.

(2) An affected source is new if you commenced construction or reconstruction of the affected source between October 6, 2006, and May 20, 2011.

(i) You must meet the applicable requirements of §§ 63.11142(a), 63.11143(a) and (b), 63.11144(a) and 63.11145 for new affected sources.

(ii) You must achieve compliance by the date specified in § 63.11141(b).

(3) If you are a new affected source as specified in paragraph (b)(2) of this section that commenced construction or reconstruction between October 6, 2006, and May 20, 2011, then after April 17, 2012, you are considered an existing affected source.

(i) You must meet the applicable requirements of §§ 63.11142(b) through (f), 63.11143(c), 63.11144(b) and 63.11145 for existing affected sources.

(ii) You must achieve compliance by the date specified in § 63.11141(d), after which time you are no longer subject to paragraphs (b)(2)(i) and (ii) of this section.

(4) An affected source is new if you commenced construction or reconstruction of the affected source after May 20, 2011.

(i) You must meet the applicable requirements of §§ 63.11142(b) through (f), 63.11143(c), 63.11144(b), and 63.11145 for new affected sources.

(ii) You must achieve compliance by the date specified in § 63.11141(e).

(iii) If components of an existing affected source are replaced such that the replacement meets the definition of reconstruction in § 63.2 and the reconstruction commenced after May 20, 2011, then the existing affected source becomes a reconstructed source and is subject to the relevant standards for a new affected source. The reconstructed source must comply with the requirements of paragraph (b)(4)(i) of this section for a new affected source upon initial startup of the reconstructed source or by April 17, 2012, whichever is later.

(c) This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the Clean Air Act. After April 17, 2012, the requirements of this subpart also do not apply to chemical manufacturing process units, as defined in § 63.101, that produce vinyl chloride monomer or other raw materials used in the production of polyvinyl chloride and copolymers.

(d) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under § 70.3(a) or § 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

(e) After the applicable compliance date specified in § 63.11141(c), (d) or (e), an affected source that is also subject to the provisions of 40 CFR part 61, subpart F, is required to comply with the provisions of this subpart and no longer has to comply with 40 CFR part 61, subpart F.

(f) After the applicable compliance date specified in § 63.11141(c), (d) or (e), an affected source that is also subject to the provisions of other 40 CFR part 60 or 40 CFR part 63 subparts is required to comply with this subpart and any other applicable 40 CFR part 60 and 40 CFR part 63 subparts.

■ 4. Section 63.11141 is revised to read as follows:

§ 63.11141 What are my compliance dates?

(a) If you own or operate an existing affected source as specified in § 63.11140(b)(1), then you must achieve compliance with the applicable provisions in this subpart specified in § 63.11140(b)(1)(i) by January 23, 2007.

(b) If you own or operate a new affected source as specified in § 63.11140(b)(2), then you must achieve compliance with the applicable provisions in this subpart as specified in § 63.11140(b)(2)(i) by the dates in paragraphs (b)(1) or (2) of this section.

(1) If you start up a new affected source on or before January 23, 2007, you must achieve compliance with the applicable provisions in this subpart not later than January 23, 2007.

(2) If you start up a new affected source after January 23, 2007, but before or on May 20, 2011, then you must achieve compliance with the provisions in this subpart upon startup of your affected source.

(c) If you own or operate an existing affected source as specified in § 63.11140(b)(1), then you must achieve compliance with the applicable provisions in this subpart specified in § 63.11140(b)(1)(iii) by April 17, 2015.

(d) If you own or operate an affected source that commenced construction or reconstruction between October 6, 2006, and May 20, 2011, then you must achieve compliance with the applicable provisions of this subpart specified in § 63.11140(b)(3) by April 17, 2015.

(e) If you own or operate a new affected source as specified in § 63.11140(b)(4), then you must achieve compliance with the applicable provisions in this subpart specified in § 63.11140(b)(4)(i) by the dates in paragraphs (e)(1) and (2) of this section.

(1) If you start up your affected source between May 20, 2011, and April 17, 2012, then you must achieve compliance with the applicable provisions in this subpart not later than April 17, 2012.

(2) If you start up your affected source after April 17, 2012, then you must achieve compliance with the provisions in this subpart upon startup of your affected source.

■ 5. Section 63.11142 is revised to read as follows:

§ 63.11142 What are the standards and compliance requirements for new and existing sources?

(a) You must meet all the requirements in 40 CFR part 61, subpart F, except for §§ 61.62 and 61.63.

(b) You must comply with each emission limit and standard specified in Table 1 to this subpart that applies to your existing affected source, and you must comply with each emission limit and standard specified in Table 2 to this subpart that applies to your new affected source.

(c) The emission limits, operating limits and work practice standards specified in this subpart apply at all times, including periods of startup, shutdown and malfunction.

(d) You must demonstrate initial compliance by the dates specified in § 63.11141.

(e) You must conduct subsequent performance testing according to the schedule specified in § 63.11905.

(f) You must meet the requirements of the applicable sections of 40 CFR part 63, subpart HHHHHHH, as specified in paragraphs (f)(1) through (19) of this section, except for the purposes of complying with this subpart, where the applicable sections of 40 CFR part 63, subpart HHHHHHH, as specified in paragraphs (f)(1) through (19) of this section reference Table 1 or Table 2 to subpart HHHHHHH, reference is made to Table 1 or Table 2 to this subpart.

(1) You must comply with the requirements of § 63.11880(b).

(2) You must comply with the requirements of §§ 63.11890(a) through 63.11890(d) and are subject to § 63.11895.

(3) You must comply with the requirements of § 63.11896, except for the purposes of complying with this subpart, where § 63.11896 refers to § 63.11870(d) of subpart HHHHHHH, reference is made to § 63.11140(b)(4) of this subpart.

(4) You must comply with the requirements of § 63.11900, except for the purposes of complying with this subpart, where § 63.11900 refers to § 63.11875 of subpart HHHHHHH, reference is made to § 63.11141 of this subpart.

(5) You must meet the requirements of § 63.11910 for initial and continuous compliance for storage vessels.

(6) You must meet the requirements of § 63.11915 for equipment leaks.

(7) You must meet the requirements of § 63.11920 for initial and continuous compliance for heat exchange systems.

(8) You must meet the requirements of § 63.11925 for initial and continuous compliance for process vents.

(9) You must meet the requirements of § 63.11930 for closed vent systems.

(10) You must meet the requirements of § 63.11935 for continuous emissions monitoring systems (CEMS) and continuous parameter monitoring systems (CPMS) to demonstrate initial and continuous compliance with the emission standards for process vents.

(11) You must meet the requirements of § 63.11940 for continuous monitoring requirements for control devices required to install CPMS to meet the emission limits for process vents.

(12) You must meet the requirements of § 63.11945 for performance testing requirements for process vents.

(13) You must meet the requirements of § 63.11950 for emissions calculations to be used for an emission profile by process of batch process operations.

(14) You must meet the requirements of § 63.11955 for initial and continuous compliance requirements for other emission sources.

(15) You must meet the requirements of § 63.11956 for ambient monitoring.

(16) You must meet the requirements of § 63.11960 for initial and continuous compliance requirements for stripped resin.

(17) You must meet the requirements of § 63.11965 through § 63.11980 for general, initial and continuous compliance, test methods and calculation procedures for wastewater.

(18) You must meet the notification and reporting requirements of § 63.11985.

(19) You must meet the recordkeeping requirements of §§ 63.11990 and 63.11995.

■ 6. Section 63.11143 is revised to read as follows:

§ 63.11143 What General Provisions apply to this subpart?

(a) All the provisions in part 61, subpart A of this chapter apply to this subpart.

(b) The provisions in subpart A of this part, applicable to this subpart are specified in paragraphs (b)(1) and (2) of this section.

(1) § 63.1(a)(1) through (10).

(2) § 63.1(b) except paragraph (b)(3), §§ 63.1(c) and 63.1(e).

(c) Section 63.11885 specifies which parts of the General Provisions in subpart A of this part apply to you.

■ 7. Section 63.11144 is revised to read as follows:

§ 63.11144 What definitions apply to this subpart?

(a) On and before April 17, 2012, the terms used in this subpart are defined in the Clean Air Act; §§ 61.02 and 61.61 of this chapter; and § 63.2 for terms used in the applicable provisions of subpart A of this part, as specified in § 63.11143(b).

(b) After April 17, 2012, terms used in this subpart are defined in the Clean Air Act; § 63.2; and § 63.12005.

■ 8. Section 63.11145 is revised to read as follows:

§ 63.11145 Who implements and enforces this subpart?

(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. If the U.S. EPA Administrator has delegated authority to a state, local or tribal agency, then that agency has the authority to implement and enforce this subpart. 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 under subpart E of this part, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the state, local or tribal agency.

(1) Approval of an alternative means of emissions imitation under § 61.12(d) of this chapter.

(2) Approval of a major change to test methods under § 61.13(h) of this chapter. A "major change to test method" is defined in § 63.90.

(3) Approval of a major change to monitoring under § 61.14(g) of this chapter. A "major change to monitoring" is defined in § 63.90.

(4) Approval of a major change to reporting under § 61.10. A "major change to recordkeeping/reporting" is defined in § 63.90.

■ 9. Table 1 and Table 2 are added to subpart DDDDDD to read as follows:

TABLE 1 TO SUBPART DDDDDD OF PART 63—EMISSION LIMITS AND STANDARDS FOR EXISTING AFFECTED SOURCES

For this type of emission point . . .	And for this air pollutant . . .	And for an affected source producing this type of PVC resin . . .	You must meet this emission limit . . .
PVC-only process vents [a]	Vinyl chloride	All resin types	5.3 parts per million by volume (ppmv).
	Total hydrocarbons	All resin types	46 ppmv measured as propane.
	Total organic HAP [b]	All resin types	140 ppmv.
	Dioxins/furans (toxic equivalency basis).	All resin types	0.13 nanograms per dry standard cubic meter (ng/dscm).
PVC-combined process vents [a].	Vinyl chloride	All resin types	0.56 ppmv.
	Total hydrocarbons	All resin types	2.3 ppmv measured as propane.
	Total organic HAP [b]	All resin types	29 ppmv.
	Dioxins/furans (toxic equivalency basis).	All resin types	0.076 ng/dscm.
Stripped resin	Vinyl chloride	Bulk resin	7.1 parts per million by weight (ppmw).
		Dispersion resin	1,500 ppmw.
		Suspension resin	36 ppmw.
		Suspension blending resin	140 ppmw.
		Copolymer resin	790 ppmw.
	Total non-vinyl chloride organic HAP	Bulk resin	170 ppmw.
		Dispersion resin	320 ppmw.
		Suspension resin	36 ppmw.
		Suspension blending resin	500 ppmw.
		Copolymer resin	1,900 ppmw.
Process Wastewater	Vinyl chloride	All resin types	2.1 ppmw.

TABLE 1 TO SUBPART DDDDDD OF PART 63—EMISSION LIMITS AND STANDARDS FOR EXISTING AFFECTED SOURCES—Continued

For this type of emission point . . .	And for this air pollutant . . .	And for an affected source producing this type of PVC resin . . .	You must meet this emission limit . . .
	Total non-vinyl chloride organic HAP	All resin types	0.018 ppmw.

[a] Emission limits at 3 percent oxygen, dry basis.
[b] Affected sources have the option to comply with either the total hydrocarbon limit or the total organic HAP limit.

TABLE 2 TO SUBPART DDDDDD OF PART 63—EMISSION LIMITS AND STANDARDS FOR NEW AFFECTED SOURCES

For this type of emission point . . .	And for this air pollutant . . .	And for an affected source producing this type of PVC resin . . .	You must meet this emission limit . . .
PVC-only process vents [a]	Vinyl chloride	All resin types	5.3 parts per million by volume (ppmv).
	Total hydrocarbons	All resin types	46 ppmv measured as propane
	Total organic HAP [b]	All resin types	140 ppmv.
	Dioxins/furans (toxic equivalency basis).	All resin types	0.13 nanograms per dry standard cubic meter (ng/dscm).
PVC-combined process vents [a].	Vinyl chloride	All resin types	0.56 ppmv.
	Total hydrocarbons	All resin types	2.3 ppmv measured as propane
	Total organic HAP [b]	All resin types	29 ppmv
	Dioxins/furans (toxic equivalency basis).	All resin types	0.076 ng/dscm.
Stripped resin	Vinyl chloride	Bulk resin	7.1 parts per million by weight (ppmw).
		Dispersion resin	1,500 ppmw.
		Suspension resin	36 ppmw.
		Suspension blending resin	140 ppmw.
		Copolymer resin	790 ppmw.
	Total non-vinyl chloride organic HAP	Bulk resin	170 ppmw.
		Dispersion resin	320 ppmw.
		Suspension resin	36 ppmw.
		Suspension blending resin	500 ppmw.
		Copolymer resin	1,900 ppmw.
Process Wastewater	Vinyl chloride	All resin types	2.1 ppmw.
	Total non-vinyl chloride organic HAP	All resin types	0.018 ppmw.

[a] Emission limits at 3 percent oxygen, dry basis.
[b] Affected sources have the option to comply with either the total hydrocarbon limit or the total organic HAP limit.

■ 10. Part 63 is amended by adding and reserving subparts FFFFFFF and GGGGGGG, and adding subpart HHHHHHH, to read as follows:

Subparts FFFFFFF and GGGGGGG—[Reserved]

Subpart HHHHHHH—National Emission Standards for Hazardous Air Pollutant Emissions for Polyvinyl Chloride and Copolymers Production

What This Subpart Covers

Sec.

63.11860 What is the purpose of this subpart?
63.11865 Am I subject to the requirements in this subpart?
63.11870 What is the affected source of this subpart?
63.11871 What is the relationship to 40 CFR part 61, subpart F?
63.11872 What is the relationship to other subparts in this part?
63.11875 When must I comply with this subpart?

Emission Limits, Operating Limits and Work Practice Standards

63.11880 What emission limits, operating limits and standards must I meet?

General Compliance Requirements

63.11885 What parts of the General Provisions apply to me?
63.11890 What are my additional general requirements for complying with this subpart?
63.11895 How do I assert an affirmative defense for exceedance of emission standard during malfunction?
63.11896 What am I required to do if I make a process change at my affected source?

Testing and Compliance Requirements

63.11900 By what date must I conduct initial performance testing and monitoring, establish any applicable operating limits and demonstrate initial compliance with my emission limits and work practice standards?
63.11905 When must I conduct subsequent performance testing and monitoring to demonstrate continuous compliance?
63.11910 What are my initial and continuous compliance requirements for storage vessels?
63.11915 What are my compliance requirements for equipment leaks?
63.11920 What are my initial and continuous compliance requirements for heat exchange systems?
63.11925 What are my initial and continuous compliance requirements for process vents?
63.11930 What requirements must I meet for closed vent systems?
63.11935 What CEMS and CPMS requirements must I meet to demonstrate initial and continuous compliance with the emission standards for process vents?
63.11940 What continuous monitoring requirements must I meet for control devices required to install CPMS to meet the emission limits for process vents?
63.11945 What performance testing requirements must I meet for process vents?
63.11950 What emissions calculations must I use for an emission profile?
63.11955 What are my initial and continuous compliance requirements for other emission sources?
63.11956 What are my compliance requirements for ambient monitoring?

63.11960 What are my initial and continuous compliance requirements for stripped resin?
63.11965 What are my general compliance requirements for wastewater?
63.11970 What are my initial compliance requirements for process wastewater?
63.11975 What are my continuous compliance requirements for process wastewater?
63.11980 What are the test methods and calculation procedures for process wastewater?

Notifications, Reports and Records

63.11985 What notifications and reports must I submit and when?
63.11990 What records must I keep?
63.11995 In what form and how long must I keep my records?
63.12000 Who implements and enforces this subpart?

Definitions

63.12005 What definitions apply to this subpart?

Tables to Subpart HHHHHHH of Part 63

Table 1 to Subpart HHHHHHH of Part 63—Emission Limits and Standards for Existing Affected Sources
Table 2 to Subpart HHHHHHH of Part 63—Emission Limits and Standards for New Affected Sources
Table 3 to Subpart HHHHHHH of Part 63—Summary of Control Requirements for Storage Vessels at New and Existing Sources
Table 4 to Subpart HHHHHHH of Part 63—Applicability of the General Provisions to Part 63
Table 5 to Subpart HHHHHHH of Part 63—Operating Parameters, Operating Limits and Data Monitoring, Recording and Compliance Frequencies for Process Vents
Table 6 to Subpart HHHHHHH of Part 63—Toxic Equivalency Factors
Table 7 to Subpart HHHHHHH of Part 63—Calibration and Accuracy Requirements for Continuous Parameter Monitoring Systems
Table 8 to Subpart HHHHHHH of Part 63—Methods and Procedures for Conducting Performance Tests for Process Vents
Table 9 to Subpart HHHHHHH of Part 63—Procedures for Conducting Sampling of Resin and Process Wastewater
Table 10 to Subpart HHHHHHH of Part 63—HAP Subject to the Stripped Resin and Process Wastewater Provisions at New and Existing Sources

Subpart HHHHHHH—National Emission Standards for Hazardous Air Pollutant Emissions for Polyvinyl Chloride and Copolymers Production

What This Subpart Covers

§ 63.11860 What is the purpose of this subpart?

This subpart establishes national emission standards for hazardous air pollutants emitted from the production of polyvinyl chloride and copolymers at major sources. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission standards.

§ 63.11865 Am I subject to the requirements in this subpart?

You are subject to the requirements in this subpart if you own or operate one or more polyvinyl chloride and copolymers production process units (PVCPU) as defined in § 63.12005 that are located at, or are part of, a major source of hazardous air pollutants (HAP) emissions as defined in § 63.2. The requirements of this subpart do not apply to research and development facilities, as defined in section 112(c)(7) of the Clean Air Act, or to chemical manufacturing process units, as defined in § 63.101, that produce vinyl chloride monomer or other raw materials used in the production of polyvinyl chloride and copolymers.

§ 63.11870 What is the affected source of this subpart?

(a) This subpart applies to each polyvinyl chloride and copolymers production affected source.

(b) The polyvinyl chloride and copolymers production affected source is the facility wide collection of PVCPU, storage vessels, heat exchange systems, surge control vessels, wastewater and process wastewater treatment systems that are associated with producing polyvinyl chloride and copolymers.

(c) An existing affected source is one for which construction was commenced on or before May 20, 2011, at a major source.

(d) A new affected source is one for which construction is commenced after May 20, 2011, at a major source.

(e) If components of an existing affected source are replaced such that the replacement meets the definition of reconstruction in § 63.2 and the reconstruction commenced after May 20, 2011, then the existing affected source becomes a reconstructed source and is subject to the relevant standards for a new affected source. The reconstructed source must comply with the requirements for a new affected source upon initial startup of the reconstructed source or by April 17, 2012, whichever is later.

§ 63.11871 What is the relationship to 40 CFR part 61, subpart F?

After the applicable compliance date specified in § 63.11875(a), (b) or (c), an affected source that is also subject to the provisions of 40 CFR part 61, subpart F, is required to comply with the provisions of this subpart and no longer has to comply with 40 CFR part 61, subpart F.

§ 63.11872 What is the relationship to other subparts in this part?

After the applicable compliance date specified in § 63.11875(a), (b) or (c), an affected source that is also subject to the provisions of other subparts in 40 CFR part 60 or this part is required to comply with this subpart and any other applicable subparts in 40 CFR part 60 or this part.

§ 63.11875 When must I comply with this subpart?

(a) If you own or operate an existing affected source, you must achieve compliance with the applicable provisions in this subpart no later than April 17, 2015. On or after April 17, 2015, any such existing affected source is no longer subject to the provisions of 40 CFR part 61, subpart F.

(b) If you start up a new affected source on or before April 17, 2012, you must achieve compliance with the provisions of this subpart no later than April 17, 2012. On or after April 17, 2012, any such new affected source is not subject to the provisions of 40 CFR part 61, subpart F.

(c) If you start up a new affected source after April 17, 2012, you must achieve compliance with the provisions of this subpart upon startup of your affected source. Upon startup, any such new affected source is not subject to the provisions of 40 CFR part 61, subpart F.

(d) You must meet the notification requirements in §§ 63.9 and 63.11985 according to the dates specified in those sections. Some of the notifications must be submitted before you are required to comply with the emission limits and standards in this subpart.

Emission Limits, Operating Limits and Work Practice Standards

§ 63.11880 What emission limits, operating limits and standards must I meet?

(a) You must comply with each emission limit and standard specified in Table 1 to this subpart that applies to your existing affected source, and you must comply with each emission limit and standard specified in Table 2 to this subpart that applies to your new affected source.

(b) You must establish an operating limit for each operating parameter required to be monitored in § 63.11925, and you must establish each operating limit as an operating range, minimum operating level or maximum operating level. You must comply with each established operating limit.

(c) You must comply with the emission limits and standards specified in §§ 63.11910 through 63.11980 that apply to your affected source.

General Compliance Requirements

§ 63.11885 What parts of the General Provisions apply to me?

Table 4 to this subpart specifies which parts of the General Provisions in subpart A of this part apply to you.

§ 63.11890 What are my additional general requirements for complying with this subpart?

(a) The emission limits, operating limits and work practice standards specified in this subpart apply at all times, including periods of startup, shutdown or malfunction.

(b) At all times, you must operate and maintain your affected source, including associated air pollution control components and monitoring system components, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether acceptable operation and maintenance procedures are being used will be based on information available to the Administrator, which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c) You must install, calibrate, maintain, and operate all monitoring system components according to §§ 63.8, 63.11935(b) and (c), and paragraphs (c)(1) and (2) of this section.

(1) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), you must operate the continuous monitoring system at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(2) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods in assessing the operation of the control device and associated control system. You must report any periods for which the monitoring system failed to collect required data.

(d) A deviation means any of the cases listed in paragraphs (d)(1) through (7) of this section.

(1) Any instance in which an affected source subject to this subpart, or an owner or operator of such a source, fails to meet any requirement or obligation established by this subpart, including, but not limited to, any emission limit, operating limit or work practice standard.

(2) When a performance test indicates that emissions of a pollutant in Table 1 or 2 to this subpart are exceeding the emission standard for the pollutant specified in Table 1 or 2 to this subpart.

(3) When a 3-hour block average from a continuous emissions monitor, as required by § 63.11925(c)(1) through (3), exceeds an emission limit in Table 1 or 2 to this subpart.

(4) When the average value of a monitored operating parameter, based on the data averaging period for compliance specified in Table 5 to this subpart, does not meet the operating limit established in § 63.11880(b).

(5) When an affected source discharges directly to the atmosphere from any of the sources specified in paragraphs (d)(5)(i) through (iv) of this section.

(i) A pressure relief device, as defined in § 63.12005.

(ii) A bypass, as defined in § 63.12005.

(iii) A closed vent system in vacuum service.

(iv) A closure device on a pressure vessel.

(6) Any instance in which the affected source subject to this subpart, or an owner or operator of such a source, fails to meet any term or condition specified in paragraph (d)(6)(i) or (ii) of this section.

(i) Any term or condition that is adopted to implement an applicable requirement in this subpart.

(ii) Any term or condition relating to compliance with this subpart that is included in the operating permit for any affected source required to obtain such a permit.

(7) Any failure to collect required data, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

§ 63.11895 How do I assert an affirmative defense for exceedance of emission standard during malfunction?

In response to an action to enforce the standards set forth in § 63.11880, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

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

(1) The violation:

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

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

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

(iv) Were not part of a recurring pattern indicative of inadequate design, operation or maintenance.

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

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

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

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

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

(7) All of the actions in response to the violations were documented by properly signed, contemporaneous operating logs.

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

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

(b) Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator in the compliance report required by § 63.11985(b) with all necessary supporting documentation, that it has met the requirements set forth in this section.

§ 63.11896 What am I required to do if I make a process change at my affected source?

If you make a process change to an existing affected source that does not meet the criteria to become a new affected source in § 63.11870(d), you must comply with the requirements in paragraph (a) of this section and the testing and reporting requirements in paragraphs (c) and (d) of this section. If you make a process change to a new affected source, you must comply with the requirements in paragraph (b) of this section and the testing and reporting requirements in paragraphs (c) and (d) of this section. Refer to § 63.12005 for the definition of process changes.

(a) You must demonstrate that the changed process unit or component of the affected facility is in compliance with the applicable requirements for an existing affected source. You must demonstrate initial compliance with the emission limits and establish any applicable operating limits in § 63.11880 within 180 days of the date of start-up of the changed process unit or component of the affected facility. You must demonstrate compliance with any applicable work practice standards upon startup of the changed process unit or component of the affected facility.

(b) You must demonstrate that all changed emission points are in compliance with the applicable requirements for a new affected source. You must demonstrate initial compliance with the emission limits and establish any applicable operating limits in § 63.11880 within 180 days of the date of startup of the changed process unit or component of the affected facility. You must demonstrate compliance with any applicable work practice standards upon startup of the changed process unit or component of the affected facility.

(c) For process changes, you must demonstrate continuous compliance with your emission limits and standards, operating limits, and work practice standards according to the procedures and frequency in §§ 63.11910 through 63.11980.

(d) For process changes, you must submit the report specified in § 63.11985(b)(4)(iii).

Testing and Compliance Requirements

§ 63.11900 By what date must I conduct initial performance testing and monitoring, establish any applicable operating limits and demonstrate initial compliance with my emission limits and work practice standards?

(a) For existing affected sources, you must establish any applicable operating limits required in § 63.11880 and demonstrate initial compliance with the emission limits and standards specified in Tables 1 and 3 to this subpart, as applicable, no later than 180 days after the compliance date specified in § 63.11875 and according to the applicable provisions in § 63.7(a)(2).

(b) For existing affected sources, you must demonstrate initial compliance with any applicable work practice standards required in § 63.11880 no later than the compliance date specified in § 63.11875 and according to the applicable provisions in § 63.7(a)(2).

(c) For new or reconstructed affected sources, you must establish any applicable operating limits required in § 63.11880, and demonstrate initial compliance with the emission limits and standards specified in Tables 2 and 3 to this subpart, as applicable, no later than 180 days after the effective date of publication of the final rule in the **Federal Register** or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) For new and reconstructed affected sources, you must demonstrate initial compliance with any applicable work practice standards required in § 63.11880 no later than the startup date of the affected source or the effective date of publication of the final rule in the **Federal Register**, whichever is later, and according to the applicable provisions in § 63.7(a)(2).

(e) If you demonstrate initial compliance using a performance test and a force majeure is about to occur, occurs, or has occurred for which you intend to assert a claim of force majeure, then you must follow the procedures in § 63.7(a)(4).

§ 63.11905 When must I conduct subsequent performance testing and monitoring to demonstrate continuous compliance?

Following the date of your initial demonstration of compliance in § 63.11900, you must conduct subsequent performance testing and monitoring to demonstrate continuous compliance with your emission limits, operating limits, and work practice standards according to the procedures and frequency in §§ 63.11910 through 63.11980. If you make a process change as specified in § 63.11896, such that a different emission limit or operating parameter limit applies, you must conduct a performance test according to § 63.11896.

§ 63.11910 What are my initial and continuous compliance requirements for storage vessels?

You must comply with the requirements specified in Table 3 to this subpart for each storage vessel in HAP service.

(a) For each fixed roof storage vessel used to comply with the requirements specified in Table 3 to this subpart, you must meet the requirements in paragraphs (a)(1) through (4) of this section. If you elect to use a fixed roof storage vessel vented to a closed vent system and control device, the closed vent system and control device must meet the requirements in §§ 63.11925 through 63.11950.

(1) *Design requirements.* (i) The fixed roof must be installed in a manner such that there are no visible cracks, holes, gaps, or other open spaces between roof section joints or between the interface of the roof edge and the tank wall.

(ii) Each opening in the fixed roof must be equipped with a closure device designed to operate such that when the closure device is secured in the closed position there are no visible cracks, holes, gaps, or other open spaces in the closure device or between the perimeter of the opening and the closure device.

(2) *Operating requirements.* (i) Except as specified in paragraph (a)(2)(ii) of this section, the fixed roof must be installed with each closure device secured in the closed position.

(ii) Opening of closure devices or removal of the fixed roof is allowed under conditions specified in paragraphs (a)(2)(ii)(A) and (B) of this section.

(A) A closure device may be opened or the roof may be removed when needed to provide access.

(B) A conservation vent that vents to the atmosphere is allowed during normal operations to maintain the tank internal operating pressure within tank design specifications. Normal operating conditions that may require these devices to open are during those times when the internal pressure of the storage vessel is outside the internal pressure operating range for the storage vessel as a result of loading or unloading operations or diurnal ambient temperature fluctuations.

(iii) During periods of planned routine maintenance of a control device, operate the storage vessel in accordance with paragraphs (a)(2)(iii)(A) and (B) of this section. You must keep the records specified in § 63.11990(b)(6).

(A) Do not add material to the storage vessel during periods of planned routine maintenance.

(B) Limit periods of planned routine maintenance for each control device to no more than 360 hours per year (hr/yr).

(3) *Inspection and monitoring requirements.* (i) Visually inspect the fixed roof and its closure devices for defects initially and at least once per calendar year except as specified in paragraph (a)(3)(ii) of this section. Defects include, but are not limited to, visible cracks, holes, or gaps in the roof sections or between the roof and the wall of the storage vessel; broken, cracked or otherwise damaged seals, or gaskets on closure devices; and broken or missing hatches, access covers, caps or other closure devices.

(ii) The inspection requirement specified in paragraph (a)(3)(i) of this section does not apply to parts of the fixed roof that you determine are unsafe to inspect because operating personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraph (a)(3)(i) of this section, provided you comply with the requirements specified in paragraphs (a)(3)(ii)(A) and (B) of this section.

(A) You prepare and maintain at the plant site written documentation that identifies all parts of the fixed roof that are unsafe to inspect and explains why such parts are unsafe to inspect.

(B) You develop and implement a written plan and schedule to conduct inspections the next time alternative storage capacity becomes available and the storage vessel can be emptied or temporarily removed from service, as necessary, to complete the inspection. The required inspections must be performed as frequently as practicable but do not need to be performed more than once per calendar year. You must maintain a copy of the written plan and schedule at the plant site.

(4) *Repair requirements.* (i) Complete repair of a defect as soon as possible, but no later than 45 days after detection. You must comply with the requirements in this paragraph (a)(4)(i) except as provided in paragraph (a)(4)(ii) of this section.

(ii) Repair of a defect may be delayed beyond 45 days if you determine that repair of the defect requires emptying or temporary removal from service of the storage vessel and no alternative storage capacity is available at the site to accept the removed material. In this case, repair the defect the next time alternative storage capacity becomes available and the storage vessel can be emptied or temporarily removed from service.

(b) If you elect to use an internal floating roof storage vessel or external floating roof storage vessel to comply with the requirements specified in Table 3 to this subpart, you must meet all requirements of §§ 63.1060 through 63.1067 of subpart WW of this part for internal floating roof storage vessels or external floating roof storage vessels, as applicable.

(c) For each pressure vessel used to comply with the requirements specified in Table 3 to this subpart, you must meet the requirements in paragraphs (c)(1) through (4) of this section.

(1) Whenever the pressure vessel is in hazardous air pollutants (HAP) service, you must operate the pressure vessel as a closed system that does not vent to the atmosphere, e.g., during filling, emptying and purging. The vent stream during filling, emptying and purging must meet the requirements of § 63.11925(a) and (b).

(2) Each opening in the pressure vessel must be equipped with a closure device designed to operate such that when the closure device is secured in the closed position there are no visible cracks, holes, gaps or other open spaces in the closure device or between the perimeter of the opening and the closure device.

(3) All potential leak interfaces must be monitored annually for leaks using the procedures specified in § 63.11915 and you may adjust for background concentration. You must comply with the recordkeeping provisions specified in § 63.11990(b)(4) and the reporting provisions specified in § 63.11985(a)(1), (b)(1), and (b)(10).

(4) Pressure vessel closure devices must not discharge to the atmosphere. Any such release (e.g., leak) constitutes a violation of this rule. You must submit to the Administrator as part of your compliance report the information specified in § 63.11985(b)(10). This report is required even if you elect to follow the procedures specified in § 63.11895 to establish an affirmative defense.

§ 63.11915 What are my compliance requirements for equipment leaks?

For equipment in HAP service (as defined in § 63.12005), you must comply with the requirements in paragraphs (a) through (c) of this section.

(a) Requirement for certain equipment in subpart UU of this part. You must comply with §§ 63.1020 through 63.1025, 63.1027, 63.1029 through 63.1032, and 63.1034 through 63.1039 of subpart UU of this part.

(b) Requirements for pumps, compressors, and agitators. You must meet the requirements of paragraphs (b)(1) and (2) of this section. For each type of equipment specified in paragraphs (b)(1) and (2) of this section, you must also meet the requirements of paragraph (a) of this section.

(1) Rotating pumps. HAP emissions from seals on all rotating pumps in HAP service are to be minimized by either installing sealless pumps, pumps with double mechanical seals or equivalent equipment, or by complying with the requirements of 40 CFR part 63, subpart UU for rotating pumps. If double mechanical seals are used, emissions from the seals are to be minimized by maintaining the pressure between the two seals so that any leak that occurs is into the pump; by complying with § 63.11925(a) and (b); or equivalent equipment or procedures approved by the Administrator.

(2) Reciprocating pumps, rotating compressors, reciprocating compressors and agitators. HAP emissions from seals on all reciprocating pumps, rotating compressors, reciprocating compressors and agitators in HAP service are to be minimized by either installing double mechanical seals or equivalent equipment, or by complying with the requirements of 40 CFR part 63, subpart UU for reciprocating pumps, rotating compressors, reciprocating compressors and/or agitators. If double mechanical seals are used, HAP emissions from the seals are to be minimized by maintaining the pressure between the two seals so that any leak that occurs is into the pump; by complying with § 63.11925(a) and (b); or equivalent equipment or procedures approved by the Administrator.

(c) Requirements for pressure relief devices. For pressure relief devices in HAP service, as defined in § 63.12005, you must meet the requirements of this

paragraph (c) and paragraph (a) of this section, you must comply with the recordkeeping provisions in § 63.11990(c), and you must comply with the reporting provisions in §§ 63.11985(a)(2), (b)(2) and (c)(7).

(1) For pressure relief devices in HAP service that discharge directly to the atmosphere without first meeting the process vent emission limits in Table 1 or 2 to this subpart by routing the discharge to a closed vent system and control device designed and operated in accordance with the requirements in §§ 63.11925 through 63.11950, you must install, maintain, and operate release indicators as specified in paragraphs (c)(1)(i) and (ii) of this section. Any release to the atmosphere without meeting the process vent emission limits in Table 1 or 2 to this subpart, constitutes a violation of this rule. You must submit the report specified in § 63.11985(c)(7), as described in paragraph (c)(1)(iii) of this section.

(i) A release indicator must be properly installed on each pressure relief device in such a way that it will indicate when an emission release has occurred.

(ii) Each indicator must be equipped with an alert system that will notify an operator immediately and automatically when the pressure relief device is open. The alert must be located such that the signal is detected and recognized easily by an operator.

(iii) For any instance that the release indicator indicates that a pressure relief device is open, you must notify operators that a pressure release has occurred, and, within 10 days of the release, you must submit to the Administrator the report specified in § 63.11985(c)(7). This report is required even if you elect to follow the procedures specified in § 63.11895 to establish an affirmative defense.

(2) For pressure relief devices in HAP service that discharge directly to a closed vent system and control device designed and operated in accordance with the requirements in §§ 63.11925 through 63.11950, and are required to meet process vent emission limits in Table 1 or 2 to this subpart. Any release to the atmosphere without meeting the process vent emission limits in Table 1 or 2 to this subpart, constitutes a violation of this rule. You must notify operators that a pressure release has occurred, and, within 10 days of the release, you must submit to the Administrator the report specified in § 63.11985(c)(7). This report is required even if you elect to follow the procedures specified in § 63.11895(b) to establish an affirmative defense.

§ 63.11920 What are my initial and continuous compliance requirements for heat exchange systems?

(a) Except as provided in paragraph (b) of this section, you must perform monitoring to identify leaks of volatile organic compounds from each heat exchange system in HAP service subject to the requirements of this subpart according to the procedures in paragraphs (a)(1) through (4) of this section.

(1) *Monitoring locations for closed-loop recirculation heat exchange systems.* For each closed loop recirculating heat exchange system, you must collect and analyze a sample from the location(s) described in either paragraph (a)(1)(i) or (ii) of this section.

(i) Each cooling tower return line prior to exposure to air for each heat exchange system in HAP service.

(ii) Selected heat exchanger exit line(s) so that each heat exchanger or group of heat exchangers within a heat exchange system is covered by the selected monitoring location(s).

(2) *Monitoring locations for once-through heat exchange systems.* For each once-through heat exchange system, you must collect and analyze a sample from the location(s) described in paragraph (a)(2)(i) of this section. You may also elect to collect and analyze an additional sample from the location(s) described in paragraph (a)(2)(ii) of this section.

(i) Selected heat exchanger exit line(s) so that each heat exchanger or group of heat exchangers in HAP service within a heat exchange system is covered by the selected monitoring location(s).

(ii) The inlet water feed line for a once-through heat exchange system prior to any heat exchanger. If multiple heat exchange systems use the same water feed (i.e., inlet water from the same primary water source), you may monitor at one representative location and use the monitoring results for that sampling location for all heat exchange systems that use that same water feed.

(3) *Monitoring method.* You must determine the total strippable volatile organic compounds concentration or vinyl chloride concentration at each monitoring location using one of the analytical methods specified in paragraphs (a)(3)(i) through (iii) of this section.

(i) Determine the total strippable volatile organic compounds concentration (in parts per million by volume) as methane from the air stripping testing system using Modified El Paso Method (incorporated by reference, see § 63.14) using a flame ionization detector analyzer.

(ii) Determine the total strippable volatile organic compounds concentration (in parts per billion by weight) in the cooling water using Method 624 at 40 CFR part 136, appendix A. The target list of compounds shall be generated based on a pre-survey sample and analysis by gas chromatography/mass spectrometry and process knowledge to include all compounds that can potentially leak into the cooling water. If Method 624 of part 136, appendix A is not applicable for all compounds that can potentially leak into the cooling water for a given heat exchange system, you cannot use this monitoring method for that heat exchange system.

(iii) Determine the vinyl chloride concentration (in parts per billion by weight) in the cooling water using Method 107 at 40 CFR part 61, appendix A.

(4) *Monitoring frequency.* You must determine the total strippable volatile organic compounds or vinyl chloride concentration at each monitoring location at the frequencies specified in paragraphs (a)(4)(i) and (ii) of this section.

(i) For heat exchange systems for which you have not delayed repair of any leaks, monitor at least monthly. You may elect to monitor more frequently than the minimum frequency specified in this paragraph.

(ii) If you elect to monitor the inlet water feed line for a once-through heat exchange system as provided in paragraph (a)(2)(ii) of this section, you must monitor the inlet water feed line at the same frequency used to monitor the heat exchange exit line(s), as required in paragraph (a)(2)(i) of this section.

(b) A heat exchange system is not subject to the monitoring requirements in paragraph (a) of this section if it meets any one of the criteria in paragraphs (b)(1) through (3) of this section.

(1) All heat exchangers that are in HAP service within the heat exchange system operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side.

(2) The heat exchange system does not contain any heat exchangers that are in HAP service.

(3) The heat exchange system has a maximum cooling water flow rate of 10 gallons per minute or less.

(c) The leak action levels for both existing and new sources are specified in paragraphs (c)(1) through (3) of this section.

(1) If you elect to monitor your heat exchange system by using the

monitoring method specified in paragraph (a)(3)(i) of this section, then the leak action level is a total strippable volatile organic compounds concentration (as methane) in the stripping gas of 3.9 parts per million by volume.

(2) If you elect to monitor your heat exchange system by using the monitoring method specified in paragraph (a)(3)(ii) of this section, then the leak action level is a total strippable volatile organic compounds concentration in the cooling water of 50 parts per billion by weight.

(3) If you elect to monitor your heat exchange system by using the monitoring method specified in paragraph (a)(3)(iii) of this section, then the leak action level is a vinyl chloride concentration in the cooling water of 50 parts per billion by weight.

(d) A leak is defined as specified in paragraph (d)(1) or (2) of this section, as applicable.

(1) For once-through heat exchange systems for which you monitor the inlet water feed, as described in paragraph (a)(2)(ii) of this section, a leak is detected if the difference in the measurement value of the sample taken from a location specified in paragraph (a)(2)(i) of this section and the measurement value of the corresponding sample taken from the location specified in paragraph (a)(2)(ii) of this section equals or exceeds the leak action level.

(2) For all other heat exchange systems, a leak is detected if a measurement value taken according to the requirements in paragraph (a) of this section equals or exceeds the leak action level.

(e) If a leak is detected, you must repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in paragraphs (f) and (g) of this section. Repair includes re-monitoring as specified in paragraph (a) of this section to verify that the measured concentration is below the applicable action level. Actions that you can take to achieve repair include but are not limited to:

(1) Physical modifications to the leaking heat exchanger, such as welding the leak or replacing a tube;

(2) Blocking the leaking tube within the heat exchanger;

(3) Changing the pressure so that water flows into the process fluid;

(4) Replacing the heat exchanger or heat exchanger bundle; or

(5) Isolating, bypassing or otherwise removing the leaking heat exchanger from service until it is otherwise repaired.

(f) If you detect a leak when monitoring a cooling tower return line or heat exchanger exit line under paragraph (a) of this section, you may conduct additional monitoring following the requirements in paragraph (a) of this section to further isolate each heat exchanger or group of heat exchangers in HAP service within the heat exchange system for which the leak was detected. If you do not detect any leaks when conducting additional monitoring for each heat exchanger or group of heat exchangers, the heat exchange system is excluded from repair requirements in paragraph (e) of this section.

(g) The delay of repair action level is defined as either a total strippable volatile organic compounds concentration (as methane) in the stripping gas of 39 parts per million by volume or a total strippable volatile organic compounds concentration in the cooling water of 500 parts per billion by weight or a vinyl chloride concentration in the cooling water of 500 parts per billion by weight. While you remain below the repair action level, you may delay the repair of a leaking heat exchanger only if one of the conditions in paragraphs (g)(1) or (2) of this section is met. If you exceed the repair action level you must repair according to paragraph (e) of this section. You must determine if a delay of repair is necessary as soon as practicable, but no later than 45 days after first identifying the leak.

(1) If the repair is technically infeasible without a shutdown and the total strippable volatile organic compounds or vinyl chloride concentration is initially and remains less than the delay of repair action level for all monitoring periods during the delay of repair, you may delay repair until the next scheduled shutdown of the heat exchange system. If, during subsequent monitoring, the total strippable volatile organic compounds or vinyl chloride concentration is equal to or greater than the delay of repair action level, you must repair the leak within 30 days of the monitoring event in which the total strippable volatile organic compounds or vinyl chloride concentration was equal to or exceeded the delay of repair action level.

(2) If the necessary equipment, parts, or personnel are not available and the total strippable volatile organic compounds or vinyl chloride concentration is initially and remains less than the delay of repair action level for all monitoring periods during the delay of repair, you may delay the repair for a maximum of 120 days from the day the leak was first identified. You must demonstrate that the necessary equipment, parts or personnel were not available. If, during subsequent monthly monitoring, the total strippable volatile organic compounds or vinyl chloride concentration is equal to or greater than the delay of repair action level, you must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded the total strippable volatile organic compounds or vinyl chloride delay of repair action level.

(h) To delay the repair under paragraph (g) of this section, you must record the information in paragraphs (h)(1) through (4) of this section.

(1) The reason(s) for delaying repair.

(2) A schedule for completing the repair as soon as practical.

(3) The date and concentration of the leak as first identified and the results of all subsequent monitoring events during the delay of repair.

(4) An estimate of the potential emissions from the leaking heat exchange system following the procedures in paragraphs (h)(4)(i) and (ii) of this section.

(i) Determine the total strippable volatile organic compounds or vinyl chloride concentration in the cooling water, in parts per billion by weight. If the Modified El Paso Method is used, calculate the total strippable volatile organic compounds concentration in the cooling water using equation 7–1 from Modified El Paso Method (incorporated by reference, see § 63.14) and the total strippable volatile organic compounds concentration measured in the stripped air.

(ii) Calculate the emissions for the leaking heat exchange system by multiplying the volatile organic compounds or vinyl chloride concentration in the cooling water, ppbw, by the flow rate of the cooling water at the selected monitoring location and by the expected duration of the delay according to Equation 1 of this section. The flow rate may be based on direct measurement, pump curves, heat balance calculations or other engineering methods.

$$E_L = (C_{VC})(10^{-9})(V_{CW})(\rho_{CW})(60)(D_{delay}) \quad \text{(Eq. 1)}$$

Where:

E_L = Emissions from leaking heat exchange system, pounds of volatile organic compounds or vinyl chloride.

C_{VC} = Actual measured concentration of total strippable volatile organic compounds or vinyl chloride measured in the cooling water, parts per billion by weight (ppbw).

V_{CW} = Total volumetric flow rate of cooling water, gallons per minute (gpm).

ρ_{CW} = Density of cooling water, pounds per gallon (lb/gal).

D_{delay} = Expected duration of the repair delay, days.

§ 63.11925 What are my initial and continuous compliance requirements for process vents?

Each process vent must meet the requirements of paragraphs (a) through (h) of this section.

(a) *Emission limits.* Each process vent must meet the emission limits in Table 1 or 2 to this subpart prior to the vent stream being exposed to the atmosphere. The emission limits in Table 1 or 2 to this subpart apply at all times. The emission limits in Table 1 or 2 to this subpart must not be met through dilution.

(b) *Closed vent systems and control devices.* Each batch process vent, continuous process vent and miscellaneous vent that is in HAP service must be routed through a closed vent system to a control device. All gas streams routed to the closed vent system and control device must be for a process purpose and not for the purpose of diluting the process vent to meet the emission limits in Table 1 or 2 to this subpart. Each control device used to comply with paragraph (a) of this section must meet the requirements of §§ 63.11925 and 63.11940, and all closed vent systems must meet the requirements in § 63.11930. You must not use a flare to comply with the emission limits in Table 1 or 2 to this subpart.

(c) *General monitoring requirements.* Except as provided in paragraphs (c)(1) through (3) of this section, for each control device used to comply with the process vent emission limit specified in Table 1 or 2 to this subpart, you must install and operate a continuous parameter monitoring system (CPMS) to monitor each operating parameter specified in § 63.11940(a) through (h) to comply with your operating limit(s) required in § 63.11880(b).

(1) Hydrogen chloride continuous emission monitoring system (CEMS). In lieu of establishing operating limits in § 63.11880(b) and using CPMS to comply with the operating limits, as specified in § 63.11940(a) through (h), upon promulgation of a performance specification for hydrogen chloride CEMS, new and existing sources have the option to install a hydrogen chloride CEMS to demonstrate initial and continuous compliance with the hydrogen chloride emission limit for process vents, as specified in paragraphs (d) and (e) of this section.

(2) Dioxin/furan CEMS. In lieu of establishing operating limits in § 63.11880(b) and using CPMS to comply with the operating limits as specified in § 63.11940(a) through (h), upon promulgation of a performance specification for dioxin/furan CEMS, new and existing sources have the option to install a dioxin/furan CEMS to demonstrate initial and continuous compliance with the dioxins/furan emission limit for process vents, as specified in paragraphs (d) and (e) of this section.

(3) Total hydrocarbon CEMS. In lieu of establishing operating limits in § 63.11880(b) and using CPMS to comply with the operating limits as specified in § 63.11940(a) through (h), new and existing affected sources have the option to install a total hydrocarbon CEMS to demonstrate initial and continuous compliance with the total hydrocarbons or total organic HAP emission limit for process vents, as specified in paragraphs (d) and (e) of this section.

(d) *Initial compliance.* To demonstrate initial compliance with the emission limits in Table 1 or 2 to this subpart, you must comply with paragraphs (d)(1) through (5) of this section.

(1) You must conduct an initial inspection as specified in § 63.11930(d) for each closed vent system.

(2) For each CEMS and CPMS required or that you elect to use as specified in paragraph (c) of this section, you must prepare the quality control program and site-specific performance evaluation test plan as specified in § 63.11935(b) and site-specific monitoring plan specified in § 63.11935(c), respectively.

(3) For each CEMS and CPMS required or that you elect to use as specified in paragraph (c) of this section, you must install, operate, and maintain the CEMS and CPMS as specified in §§ 63.11935(b) and (c), respectively, and you must conduct an initial site-specific performance evaluation test according to your site-specific monitoring plan and §§ 63.11935(b)(3) and (c)(4), respectively.

(4) For each emission limit for which you use a CEMS to demonstrate compliance, you must meet the requirements specified in § 63.11890(c), and you must demonstrate initial compliance with the emission limits in Table 1 or 2 to this subpart based on 3-hour block averages of CEMS data collected at the minimum frequency specified in § 63.11935(b)(2) and calculated using the data reduction method specified in § 63.11935(e). For a CEMS used on a batch operation, you may use a data averaging period based on an operating block in lieu of the 3-hour averaging period.

(5) For each emission limit in Table 1 or 2 for which you do not use a CEMS to demonstrate compliance, you must meet the requirements of paragraphs (d)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test according to the requirements in § 63.11945 to demonstrate compliance with the total hydrocarbons or total organic HAP emission limit, vinyl chloride emission limit, hydrogen chloride emission limit, and dioxin/furan emission limit in Table 1 or 2 to this subpart.

(ii) During the performance test specified in paragraph (d)(5)(i) of this section, for each CPMS installed and operated as specified in paragraph (c) of this section, you must establish an operating limit as the operating parameter range, minimum operating parameter level, or maximum operating parameter level specified in § 63.11935(d). You must meet the requirements specified in § 63.11890(c). Each operating limit must be based on the data averaging period for compliance specified in Table 5 to this subpart using data collected at the minimum frequency specified in § 63.11935(c)(2) and calculated using the data reduction method specified in § 63.11935(e). For a CPMS used on a batch operation, you may use a data averaging period based on an operating block in lieu of the averaging period specified in Table 5 to this subpart.

(e) *Continuous compliance.* To demonstrate continuous compliance with the emission limits in Table 1 or 2 to this subpart for each process vent, you must comply with paragraphs (e)(1) through (5) of this section.

(1) You must meet the requirements in § 63.11930 for each closed vent system.

(2) You must operate and maintain each CEMS and CPMS required in paragraph (c) of this section as specified in § 63.11935(b) and (c), respectively.

(3) For each emission limit for which you use a CEMS to demonstrate compliance, you must meet the requirements in paragraphs (e)(3)(i) and (ii) of this section.

(i) You must conduct a periodic site-specific CEMS performance evaluation test according to your quality control program and site-specific performance evaluation test plan specified in § 63.11935(b)(1).

(ii) You must demonstrate continuous compliance with the emission limits in Table 1 or 2 to this subpart based on 3-hour block averages of CEMS data collected at the minimum frequency specified in § 63.11935(b)(2), and calculated using the data reduction method specified in § 63.11935(e). You must meet the requirements specified in § 63.11890(c). For a CEMS used on a batch operation, you may use a data averaging period based on an operating block in lieu of the 3-hour averaging period.

(4) For each emission limit for which you do not use a CEMS to demonstrate compliance, you must meet the requirements of paragraphs (e)(4)(i) and (ii) of this section.

(i) You must conduct a performance test once every 5 years according to the requirements in § 63.11945 for each pollutant in Table 1 or 2 to this subpart.

(ii) For each CPMS operated and maintained as specified in paragraph (e)(2) of this section, you must meet the requirements specified in paragraphs (e)(4)(ii)(A) through (C) of this section.

(A) You must conduct periodic site-specific CPMS performance evaluation tests according to your site-specific monitoring plan and § 63.11935(c).

(B) For each control device being monitored, you must continuously collect CPMS data consistent with § 63.11890(c) and your site-specific monitoring plan. You must continuously determine the average value of each monitored operating parameter based on the data collection and reduction methods specified in §§ 63.11935(c)(2) and 63.11935(e), and the applicable data averaging period for compliance specified in Table 5 to this subpart for all periods the process is operating. For a CPMS used on a batch operation, you may use a data averaging period based on an operating block in lieu of the averaging periods specified in Table 5 to this subpart.

(C) You must demonstrate continuous compliance with each operating limit established in paragraph (d)(5)(ii) of this section using these average values calculated in paragraph (e)(4)(ii)(B) of this section.

(5) Each closed vent system and control device used to comply with an emission limit in Table 1 or 2 to this subpart must be operated at all times when emissions are vented to, or collected by, these systems or devices.

(f) To demonstrate compliance with the dioxin/furan toxic equivalency emission limit specified in Table 1 or 2 to this subpart, you must determine dioxin/furan toxic equivalency as specified in paragraphs (f)(1) through (3) of this section.

(1) Measure the concentration of each dioxin/furan (tetra-through octachlorinated) congener emitted using Method 23 at 40 CFR part 60, appendix A–7.

(2) For each dioxin/furan (tetra-through octachlorinated) congener measured in accordance with paragraph (f)(1) of this section, multiply the congener concentration by its corresponding toxic equivalency factor specified in Table 6 to this subpart.

(3) Sum the products calculated in accordance with paragraph (f)(2) of this section to obtain the total concentration of dioxins/furans emitted in terms of toxic equivalency.

(g) *Emission profile.* You must characterize each process vent by developing an emissions profile for each contributing continuous process vent, miscellaneous vent and batch process vent according to paragraphs (g)(1) through (3) of this section.

(1) For batch process vents, the emissions profile must:

(i) Describe the characteristics of the batch process vent under worst-case conditions.

(ii) Determine emissions per episode and batch process vent emissions according to the procedures specified in § 63.11950.

(2) For continuous process vents, the flow rate and concentration must be determined according to paragraphs (g)(2)(i) through (iii) or according to paragraph (g)(2)(iv):

(i)(A) Method 1 or 1A of 40 CFR part 60, appendix A–1, as appropriate, shall be used for selection of the sampling site. The sampling site shall be after the last recovery device (if any recovery devices are present) but prior to being combined with any other continuous process vent, batch process vent, or miscellaneous vent, prior to the inlet of any control device that is present and prior to release to the atmosphere.

(B) No traverse site selection method is needed for vents smaller than 0.10 meter in diameter.

(ii) The gas volumetric flow rate shall be determined using Method 2, 2A, 2C or 2D of 40 CFR part 60, appendix A–1, as appropriate.

(iii) (A) Method 18 of 40 CFR part 60, appendix A–6 or Method 25A of 40 CFR part 60, appendix A–7 shall be used to measure concentration; alternatively, any other method or data that has been validated according to the protocol in Method 301 of appendix A of this part may be used.

(B) Where Method 18 of 40 CFR part 60, appendix A–6 is used, the following procedures shall be used to calculate parts per million by volume concentration:

(*1*) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(*2*) The concentration of either total organic compounds (TOC) (minus methane and ethane) or organic HAP shall be calculated according to paragraph (g)(2)(iii)(B)(2)(i) or (g)(2)(iii)(B)(2)(ii) of this section as applicable.

(*i*) The TOC concentration (C_{TOC}) is the sum of the concentrations of the individual components and shall be computed for each run using Equation 1 of this section:

$$C_{TOC} = \frac{\sum_{i=1}^{X}\left(\sum_{j=1}^{n} C_{ji}\right)}{X} \qquad \text{(Eq. 1)}$$

Where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of the sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(*ii*) The total organic HAP concentration (CHAP) shall be computed according to Equation 1 of this section except that only the organic HAP species shall be summed. The list of organic HAP is provided in Table 2 to subpart F of this part.

(C) Where Method 25A of 40 CFR part 60, appendix A–7 is used, the following procedures shall be used to calculate parts per million by volume TOC concentration:

(*1*) Method 25A of 40 CFR part 60, appendix A–7, shall be used only if a single organic HAP compound is greater than 50 percent of total organic HAP, by volume, in the vent stream.

(*2*) The vent stream composition may be determined by either process knowledge, test data collected using an appropriate EPA method, or a method or data validated according to the protocol in Method 301 of appendix A of this part. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions.

(*3*) The organic HAP used as the calibration gas for Method 25A of 40 CFR part 60, appendix A–7 shall be the single organic HAP compound present at greater than 50 percent of the total organic HAP by volume.

(*4*) The span value for Method 25A of 40 CFR part 60, appendix A–7 shall be 50 parts per million by volume.

(*5*) Use of Method 25A of 40 CFR part 60, appendix A–7 is acceptable if the response from the high-level calibration gas is at least 20 times the standard deviation of the response from the zero calibration gas when the instrument is zeroed on the most sensitive scale.

(iv) Engineering assessment including, but not limited to, the following:

(A) Previous test results provided the tests are representative of current operating practices at the process unit.

(B) Bench-scale or pilot-scale test data representative of the process under representative operating conditions.

(C) Maximum flow rate, TOC emission rate, organic HAP emission rate, or net heating value limit specified or implied within a permit limit applicable to the process vent.

(D) Design analysis based on accepted chemical engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(*1*) Use of material balances based on process stoichiometry to estimate maximum organic HAP concentrations,

(*2*) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities,

(*3*) Estimation of TOC or organic HAP concentrations based on saturation conditions,

(*4*) Estimation of maximum expected net heating value based on the vent stream concentration of each organic compound or, alternatively, as if all TOC in the vent stream were the compound with the highest heating value.

(E) All data, assumptions, and procedures used in the engineering assessment shall be documented.

(3) For miscellaneous process vents the emissions profile must be determined according to paragraph (g)(2)(iv) of this section.

(h) *Process changes.* Except for temporary shutdowns for maintenance activities, if you make a process change such that, as a result of that change, you are subject to a different process vent limit in Table 1 or 2 to this subpart, then you must meet the requirements of § 63.11896.

§ 63.11930 What requirements must I meet for closed vent systems?

(a) *General.* To route emissions from process vents subject to the emission limits in Table 1 or 2 to this subpart to a control device, you must use a closed vent system and meet the requirements of this section and all provisions referenced in this section. However, if you operate and maintain your closed vent system in vacuum service as defined in § 63.12005, you must meet the requirements in paragraph (h) of this section and are not required to meet the requirements in paragraphs (a) through (g) of this section.

(b) *Collection of emissions.* Each closed vent system must be designed and operated to collect the HAP vapors from each continuous process vent, miscellaneous process vent and batch process vent, and to route the collected vapors to a control device.

(c) *Bypass.* For each closed vent system that contains a bypass as defined in § 63.12005 (*e.g.*, diverting a vent stream away from the control device), you must not discharge to the atmosphere through the bypass. Any such release constitutes a violation of this rule. The use of any bypass diverted to the atmosphere during a performance test invalidates the performance test. You must comply with the provisions of either paragraph (c)(1) or (2) of this section for each closed vent system that contains a bypass that could divert a vent stream to the atmosphere.

(1) Bypass flow indicator. Install, maintain, and operate a flow indicator as specified in paragraphs (c)(1)(i) through (iv) of this section.

(i) The flow indicator must be properly installed at the entrance to any bypass.

(ii) The flow indicator must be equipped with an alarm system that will alert an operator immediately, and automatically when flow is detected in the bypass. The alarm must be located such that the alert is detected and recognized easily by an operator.

(iii) If the alarm is triggered, you must immediately initiate procedures to identify the cause of the alarm. If any closed vent system has discharged to the atmosphere through a vent or bypass, you must initiate procedures to stop the bypass discharge.

(iv) For any instances where the flow indicator alarm is triggered, you must submit to the Administrator as part of your compliance report, the information specified in § 63.11985(b)(9) and (10). This report is required even if you elect to follow the procedures specified in § 63.11895 to establish an affirmative defense and submit the reports specified in § 63.11985(b)(11).

(2) Bypass valve configuration. Secure the bypass valve in the non-diverting position with a car-seal or a lock-and-key type configuration.

(i) You must visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position, and the vent stream is not diverted through the bypass. A broken seal or closure mechanism or a diverted valve constitutes a violation from the emission limits in Table 1 or 2 to this subpart. You must maintain the records specified in paragraph (g)(1)(ii) of this section.

(ii) For each seal or closure mechanism, you must comply with either paragraph (c)(2)(ii)(A) or (B) of this section.

(A) For each instance that you change the bypass valve to the diverting position, you must submit to the Administrator as part of your compliance report, the information specified in § 63.11985(b)(9) and (10). This report is required even if you elect to follow the procedures specified in § 63.11895 to establish an affirmative defense and submit the reports specified in § 63.11985(b)(11).

(B) You must install, maintain, and operate a bypass flow indicator as specified in paragraphs (c)(1)(i) and (ii) of this section and you must meet the requirements in paragraph (c)(1)(iii) and (iv) of this section for each instance that the flow indicator alarm is triggered.

(d) *Closed vent system inspection and monitoring requirements.* Except as provided in paragraph (d)(3) of this section, you must inspect each closed vent system as specified in paragraph (d)(1) or (2) of this section.

(1) Hard-piping inspection. If the closed vent system is constructed of hard-piping, you must comply with the requirements specified in paragraphs (d)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the procedures in paragraph (e) of this section.

(ii) Conduct annual inspections for visible, audible, or olfactory indications of leaks.

(2) Ductwork inspection. If the closed vent system is constructed of ductwork, you must conduct initial and annual inspections according to the procedures in paragraph (e) of this section.

(3) Equipment that is unsafe to inspect. You may designate any parts of the closed vent system as unsafe to inspect if you determine that personnel would be exposed to an immediate danger as a consequence of complying with the initial and annual closed vent system inspection requirements of this subpart.

(e) *Closed vent system inspection procedures.* Except as provided in paragraph (e)(4) of this section, you must comply with all provisions of paragraphs (e)(1) through (3) of this section.

(1) General. Inspections must be performed during periods when HAP is being collected by or vented through the closed vent system. A leak is indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspection.

(2) Inspection procedures. Each closed vent system subject to this paragraph (e)(2) must be inspected according to the procedures specified in paragraphs (e)(2)(i) through (vii) of this section.

(i) Inspections must be conducted in accordance with Method 21 at 40 CFR part 60, appendix A–7, except as otherwise specified in this section.

(ii) Except as provided in paragraph (e)(2)(iii) of this section, the detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A–7, except the instrument response factor criteria in section 8.1.1.2 of Method 21 must be for the representative composition of the process fluid and not of each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, water or other inerts that are not organic HAP or volatile organic compound, the representative stream response factor must be determined on an inert-free basis. You may determine the response factor at any concentration for which you will monitor for leaks.

(iii) If no instrument is available at the plant site that will meet the performance criteria of Method 21 at 40 CFR part 60, appendix A–7 specified in paragraph (e)(2)(ii) of this section, the instrument readings may be adjusted by multiplying by the representative response factor of the process fluid, calculated on an inert-free basis as described in paragraph (e)(2)(ii) of this section.

(iv) The detection instrument must be calibrated before use on each day of its use by the procedures specified in Method 21 at 40 CFR part 60, appendix A–7.

(v) Calibration gases must be as specified in paragraphs (e)(2)(v)(A) through (D) of this section.

(A) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(B) Mixtures of methane in air at a concentration less than 10,000 parts per million by volume. A calibration gas other than methane in air may be used if the instrument does not respond to methane or if the instrument does not meet the performance criteria specified in paragraph (e)(2)(ii) of this section. In such cases, the calibration gas may be a mixture of one or more of the compounds to be measured in air.

(C) If the detection instrument's design allows for multiple calibration scales, then the lower scale must be calibrated with a calibration gas that is no higher than 2,500 parts per million by volume.

(D) Perform a calibration drift assessment, 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 at 40 CFR part 60, appendix A–7, 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 paragraph (g)(4) of this section. Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by the value specified in paragraph (e)(2)(v)(D)(*1*) of this section 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 your discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by the value specified in paragraph (e)(2)(v)(D)(*2*) of this section may be re-monitored.

(*1*) 100 minus the percent of negative drift, divided by 100.

(*2*) 100 plus the percent of positive drift, divided by 100.

(vi) You may elect to adjust or not adjust instrument readings for background. If you elect not to adjust readings for background, all such instrument readings must be compared directly to 500 parts per million by volume to determine whether there is a leak. If you elect to adjust instrument readings for background, you must measure background concentration using the procedures in this section. You must subtract the background reading from the maximum concentration indicated by the instrument.

(vii) If you elect to adjust for background, the arithmetic difference between the maximum concentration indicated by the instrument and the background level must be compared with 500 parts per million by volume for determining whether there is a leak.

(3) Instrument probe. The instrument probe must be traversed around all potential leak interfaces as described in Method 21 at 40 CFR part 60, appendix A–7.

(4) Unsafe-to-inspect written plan requirements. For equipment designated as unsafe to inspect according to the provisions of paragraph (d)(3) of this section, you must maintain and follow a written plan that requires inspecting the equipment as frequently as practical during safe-to-inspect times, but not more frequently than the annual inspection schedule otherwise applicable. You must still repair unsafe-to-inspect equipment according to the procedures in paragraph (f) of this section if a leak is detected.

(f) *Closed vent system leak repair provisions.* The provisions of this paragraph (f) apply to closed vent systems collecting HAP from an affected source.

(1) Leak repair general for hard-piping. If there are visible, audible, or olfactory indications of leaks at the time

of the annual visual inspections required by paragraph (d)(1)(ii) of this section, you must follow the procedure specified in either paragraph (f)(1)(i) or (ii) of this section.

(i) You must eliminate the leak.

(ii) You must monitor the equipment according to the procedures in paragraph (e) of this section and comply with the leak repair provisions in paragraph (f)(2) of this section.

(2) Leak repair schedule. Leaks must be repaired as soon as practical, except as provided in paragraph (f)(3) of this section.

(i) A first attempt at repair must be made no later than 5 days after the leak is detected.

(ii) Except as provided in paragraph (f)(3) of this section, repairs must be completed no later than 15 days after the leak is detected or at the beginning of the next introduction of vapors to the system, whichever is later.

(3) Delay of repair. Delay of repair of a closed vent system for which leaks have been detected is allowed if repair within 15 days after a leak is detected is technically infeasible or unsafe without a closed vent system shutdown or if you determine that emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. Repair of such equipment must be completed as soon as practical, but not later than the end of the next closed vent system shutdown.

(g) *Closed vent system records.* For closed vent systems, you must record the information specified in paragraphs (g)(1) through (5) of this section, as applicable.

(1) Bypass records. For each closed vent system that contains a bypass that could divert a vent stream away from the control device and to the atmosphere, or cause air intrusion into the control device, you must keep a record of the information specified in either paragraph (g)(1)(i) or (ii) of this section, as applicable.

(i) You must maintain records of any alarms triggered because flow was detected in the bypass, including the date and time the alarm was triggered, the duration of the flow in the bypass, as well as records of the times of all periods when the vent stream is diverted from the control device or the flow indicator is not operating.

(ii) Where a seal mechanism is used to comply with paragraph (c)(2) of this section, hourly records of flow are not required. In such cases, you must record that the monthly visual inspection of the seals or closure mechanisms has been done, and must record the occurrence of all periods when the seal mechanism is broken, the bypass valve position has changed, or the key for a lock-and-key type lock has been checked out, and records of any car-seal that has been broken.

(2) Inspection records. For each instrumental or visual inspection conducted in accordance with paragraph (d)(1) or (2) of this section for closed vent systems collecting HAP from an affected source during which no leaks are detected, you must record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(3) Leak records. When a leak is detected from a closed vent system collecting HAP from an affected source, the information specified in paragraphs (g)(3)(i) through (vi) of this section must be recorded and kept for 5 years.

(i) The instrument and the equipment identification number and the operator name, initials, or identification number.

(ii) The date the leak was detected and the date of the first attempt to repair the leak.

(iii) The date of successful repair of the leak.

(iv) The maximum instrument reading measured by the procedures in paragraph (e) of this section after the leak is successfully repaired.

(v) Repair delayed and the reason for the delay if a leak is not repaired within 15 days after discovery of the leak. You may develop a written procedure that identifies the conditions that justify a delay of repair. In such cases, reasons for delay of repair may be documented by citing the relevant sections of the written procedure.

(vi) Copies of the compliance reports as specified in § 63.11985(b)(9), if records are not maintained on a computerized database capable of generating summary reports from the records.

(4) Instrument calibration records. You must maintain records of the information specified in paragraphs (g)(4)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 at 40 CFR part 60, appendix A–7, and paragraph (e) of this section.

(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 at 40 CFR part 60, appendix A–7.

(v) Results of each calibration drift assessment required by paragraph (e)(2)(v)(D) of this section (*i.e.*, instrument reading for calibration at end of the monitoring day and the calculated percent difference from the initial calibration value).

(vi) If you make your own calibration gas, a description of the procedure used.

(5) Unsafe-to-inspect records. If you designate equipment as unsafe-to-inspect as specified in paragraph (d)(3) of this section, you must keep the records specified in paragraph (g)(5)(i) and (ii) of this section.

(i) You must maintain the identity of unsafe-to-inspect equipment as specified in paragraph (d)(3) of this section.

(ii) You must keep a written plan for inspecting unsafe-to-inspect equipment as required by paragraph (e)(4) of this section and record all activities performed according to the written plan.

(h) Closed vent systems in vacuum service. If you operate and maintain a closed vent system in vacuum service as defined in § 63.12005, you must comply with the requirements in paragraphs (h)(1) through (3) of this section, and you are not required to comply with any other provisions of this section. Any incidence where a closed vent system designed to be in vacuum service is operating and not in vacuum service constitutes a violation of this rule, unless the closed vent system is meeting the requirements in paragraphs (a) through (g) of this section for closed vent systems that are not in vacuum service. Any such incidence during a performance test invalidates the performance test.

(1) In vacuum service alarm. You must install, maintain, and operate a pressure gauge and alarm system that will alert an operator immediately and automatically when the pressure is such that the closed vent system no longer meets the definition of in vacuum service as defined in § 63.12005. The alarm must be located such that the alert is detected and recognized easily by an operator.

(2) In vacuum service alarm procedures. If the alarm is triggered for a closed vent system operating in vacuum service as specified in paragraph (h)(1) of this section, you must immediately initiate procedures to identify the cause of the alarm. If the closed vent system is not in vacuum service, you must initiate procedures to get the closed vent system back in vacuum service as defined in § 63.12005, or you must immediately comply with the requirements in paragraphs (a) through (g) of this section

for closed vent systems that are not in vacuum service.

(3) In vacuum service alarm records and reports. For any incidences where a closed vent system designed to be in vacuum service is not in vacuum service, you must submit to the Administrator as part of your compliance report, the information specified in § 63.11985(b)(10). This report is required even if you elect to follow the procedures specified in § 63.11895 to establish an affirmative defense and submit the reports specified in § 63.11985(b)(11).

§ 63.11935 What CEMS and CPMS requirements must I meet to demonstrate initial and continuous compliance with the emission standards for process vents?

(a) *General requirements for CEMS and CPMS.* You must meet the requirements in paragraph (b) of this section for each CEMS specified in § 63.11925(c) used to demonstrate compliance with the emission limits for process vents in Table 1 or 2 to this subpart. You must meet the CPMS requirements in paragraph (c) of this section and establish your operating limits in paragraph (d) of this section for each operating parameter specified in Table 5 to this subpart for each process vent control device specified in § 63.11925(b) that is used to comply with the emission limits for process vents in Table 1 or 2 to this subpart, except that flow indicators specified in § 63.11940(a) are not subject to the requirements of this section.

(b) *CEMS.* You must install, operate, and maintain each CEMS according to paragraphs (b)(1) through (7) of this section and continuously monitor emissions.

(1) You must prepare your quality control program and site-specific performance evaluation test plan, as specified in § 63.8(d) and (e). You must submit your performance evaluation test plan to the Administrator for approval, as specified in § 63.8(e)(3).

(2) The monitoring equipment must be capable of providing a continuous record, recording data at least once every 15 minutes.

(3) You must conduct initial and periodic site-specific performance evaluations and any required tests of each CEMS according to your quality control program and site-specific performance evaluation test plan prepared as specified in § 63.8(d) and (e).

(4) If supplemental gases are added to the control device, you must correct the measured concentrations in accordance with § 63.11945(d)(3).

(5) You must operate and maintain the CEMS in continuous operation according to the quality control program and performance evaluation test plan. CEMS must record data at least once every 15 minutes.

(6) CEMS must meet the minimum accuracy and calibration frequency requirements specified in the performance specifications specified in paragraphs (b)(6)(i) and (ii) of this section, as applicable.

(i) A hydrogen chloride or dioxin/furan CEMS must meet the requirements of the promulgated performance specification for the CEMS.

(ii) A total hydrocarbon CEMS must meet the requirements of 40 CFR Part 60, Appendix B, performance specification 8A.

(7) Before commencing or ceasing use of a CEMS system, you must notify the Administrator as specified in paragraphs (b)(7)(i) and (ii) of this section.

(i) You must notify the Administrator 1 month before starting use of the continuous emissions monitoring system.

(ii) You must notify the Administrator 1 month before stopping use of the continuous emissions monitoring system, in which case you must also conduct a performance test within 60 days of ceasing operation of the system.

(c) *CPMS.* You must install, maintain, and operate each CPMS as specified in paragraphs (c)(1) through (6) of this section and continuously monitor operating parameters.

(1) As part of your quality control program and site-specific performance evaluation test plan prepared as specified in § 63.8(d) and (e), you must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements specified in paragraphs (c)(1)(i) through (v) of this section and § 63.8(d). You are not required to submit the plan for approval unless requested by the Administrator. You may request approval of monitoring system quality assurance and quality control procedure alternatives to those specified in paragraphs (c)(1)(i) through (v) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, calibrations, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (3).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1) and (e)(2)(i).

(2) The monitoring equipment must be capable of providing a continuous record, recording data at least once every 15 minutes.

(3) You must install, operate, and maintain each CPMS according to the procedures and requirements in your site-specific monitoring plan.

(4) You must conduct an initial and periodic site-specific performance evaluation tests of each CPMS according to your site-specific monitoring plan.

(5) All CPMS must meet the specific parameter (*e.g.*, minimum accuracy and calibration frequency) requirements specified in § 63.11940 and Table 7 to this subpart.

(6) Monitoring equipment for temperature, pressure, volumetric flow rate, mass flow rate and conductivity must be capable of measuring the appropriate parameter over a range that extends at least 20 percent beyond the normal expected operating range of values for that parameter. The data recording system associated with affected CPMS must have a resolution that is equal to or better than one-half of the required system accuracy.

(d) *Establish operating limit.* For each operating parameter that must be monitored in § 63.11925(c) for process vent control devices, you must establish an operating limit as specified in paragraphs (d)(1) through (4) of this section. You must establish each operating limit as an operating parameter range, minimum operating parameter level, or maximum operating parameter level as specified in Table 7 to this subpart. Where this subpart does not specify which format to use for your operating limit (*e.g.*, operating range or minimum operating level), you must determine which format is best to establish proper operation of the control device such that you are meeting the emission limits specified in Table 1 or 2 to this subpart.

(1) For process vent control devices, the operating limit established for each monitored parameter specified in § 63.11940 must be based on the operating parameter values recorded during any performance test conducted to demonstrate compliance as required by § 63.11925(d)(4) and (e)(4) and may be supplemented by engineering assessments and/or manufacturer's recommendations. You are not required

to conduct performance tests over the entire range of allowed operating parameter values. The established operating limit must represent the conditions for which the control device is meeting the emission limits specified in Table 1 or 2 to this subpart.

(2) You must include as part of the notification of compliance status or the operating permit application or amendment, the information in paragraphs (d)(2)(i) through (iv) of this section, as applicable, for each process vent control device requiring operating limits.

(i) Descriptions of monitoring devices, monitoring frequencies and operating scenarios.

(ii) The established operating limit of the monitored parameter(s).

(iii) The rationale for the established operating limit, including any data and calculations used to develop the operating limit and a description of why the operating limit indicates proper operation of the control device.

(iv) The rationale used to determine which format to use for your operating limit (*e.g.*, operating range, minimum operating level or maximum operating level), where this subpart does not specify which format to use.

(3) For batch processes, you may establish operating limits for individual batch emission episodes, including each distinct episode of process vent emissions or each individual type of batch process that generates wastewater, if applicable. You must provide rationale in a batch precompliance report as specified in § 63.11985(c)(2) instead of the notification of compliance status for the established operating limit. You must include any data and calculations used to develop the operating limits and a description of why each operating limit indicates proper operation of the control device during the specific batch emission episode.

(4) If you elect to establish separate operating limits for different batch emission episodes within a batch process as specified in paragraph (d)(3) of this section, you must maintain daily records indicating each point at which you change from one operating limit to another, even if the monitoring duration for an operating limit is less than 15 minutes. You must maintain a daily record according to § 63.11990(e)(4)(i).

(e) *Reduction of CPMS and CEMS data.* You must reduce CEMS and CPMS data to 1-hour averages according to § 63.8(g) to compute the average values for demonstrating compliance specified in §§ 63.11925(e)(3)(ii), 63.11925(e)(4)(ii)(B), and 63.11960(c)(2) for CEMS and CPMS, as applicable.

§ 63.11940 What continuous monitoring requirements must I meet for control devices required to install CPMS to meet the emission limits for process vents?

As required in § 63.11925(c), you must install and operate the applicable CPMS specified in paragraphs (a) through (g) of this section for each control device you use to comply with the emission limits for process vents in Table 1 or 2 to this subpart. You must monitor, record, and calculate CPMS data averages as specified in Table 7 to this subpart. Paragraph (h) of this section provides an option to propose alternative monitoring parameters or procedures.

(a) *Flow indicator.* If flow to a control device could be intermittent, you must install, calibrate, and operate a flow indicator at the inlet or outlet of the control device to identify periods of no flow.

(b) *Thermal oxidizer monitoring.* If you are using a thermal oxidizer to meet an emission limit in Table 1 or 2 to this subpart and you are required to use CPMS as specified in § 63.11925(c), you must equip the thermal oxidizer with the monitoring equipment specified in paragraphs (b)(1) through (3) of this section, as applicable.

(1) If a thermal oxidizer other than a catalytic thermal oxidizer is used, you must install a temperature monitoring device in the fire box or in the ductwork immediately downstream of the fire box in a position before any substantial heat exchange occurs.

(2) Except as provided in paragraph (b)(3) of this section, where a catalytic thermal oxidizer is used, you must install temperature monitoring devices in the gas stream immediately before and after the catalyst bed. You must monitor the temperature differential across the catalyst bed.

(3) Instead of complying with paragraph (b)(2) of this section, and if the temperature differential between the inlet and outlet of the catalytic thermal oxidizer during normal operating conditions is less than 10 degrees Celsius (18 degrees Fahrenheit), you may elect to monitor the inlet temperature and conduct catalyst checks as specified in paragraphs (b)(3)(i) and (ii) of this section.

(i) You must conduct annual sampling and analysis of the catalyst activity (*i.e.*, conversion efficiency) following the manufacturer's or catalyst supplier's recommended procedures. If problems are found during the catalyst activity test, you must replace the catalyst bed or take other corrective action consistent with the manufacturer's recommendations within 15 days or by the next time any process vent stream is collected by the control device, whichever is sooner.

(ii) You must conduct annual internal inspections of the catalyst bed to check for fouling, plugging, or mechanical breakdown. You must also inspect the bed for channeling, abrasion, and settling. If problems are found during the annual internal inspection of the catalyst, you must replace the catalyst bed or take other corrective action consistent with the manufacturer's recommendations within 15 days or by the next time any process vent stream is collected by the control device, whichever is later. If the catalyst bed is replaced and is not of like or better kind and quality as the old catalyst then you must conduct a new performance test according to § 63.11945 to determine destruction efficiency. If a catalyst bed is replaced and the replacement catalyst is of like or better kind and quality as the old catalyst, then a new performance test to determine destruction efficiency is not required.

(c) *Absorber and acid gas scrubber monitoring.* If you are using an absorber or acid gas scrubber to meet an emission limit in Table 1 or 2 to this subpart and you are required to use CPMS as specified in § 63.11925(c), you must install the monitoring equipment specified in paragraphs (c)(1) through (3) of this section.

(1) Install and operate the monitoring equipment as specified in either paragraph (c)(1)(i) or (ii) of this section.

(i) A flow meter to monitor the absorber or acid gas scrubber influent liquid flow.

(ii) A flow meter to monitor the absorber or acid gas scrubber influent liquid flow and the gas stream flow using one of the procedures specified in paragraphs (c)(1)(ii)(A), (B), or (C) of this section. You must monitor the liquid-to-gas ratio determined by dividing the flow rate of the absorber or acid gas scrubber influent by the gas flow rate. The units of measure must be consistent with those used to calculate this ratio during the performance test.

(A) Determine gas stream flow using the design blower capacity, with appropriate adjustments for pressure drop.

(B) Measure the gas stream flow at the absorber or acid gas scrubber inlet.

(C) If you have previously determined compliance for a scrubber that requires a determination of the liquid-to-gas ratio, you may use the results of that test provided the test conditions are representative of current operation.

(2) Install and operate the monitoring equipment as specified in either paragraph (c)(2)(i), (ii), or (iii) of this section.

(i) Install and operate pressure gauges at the inlet and outlet of the absorber or acid gas scrubber to monitor the pressure drop through the absorber or acid gas scrubber.

(ii) If the difference in the inlet gas stream temperature and the inlet liquid stream temperature is greater than 38 degrees Celsius, you may install and operate a temperature monitoring device at the scrubber gas stream exit.

(iii) If the difference between the specific gravity of the scrubber effluent scrubbing fluid and specific gravity of the scrubber inlet scrubbing fluid is greater than or equal to 0.02 specific gravity units, you may install and operate a specific gravity monitoring device on the inlet and outlet of the scrubber.

(3) If the scrubbing liquid is a reactant (e.g., lime, ammonia hydroxide), you must install and operate one of the devices listed in either paragraph (c)(3)(i), (ii) or (iii) of this section.

(i) A pH monitoring device to monitor the pH of the scrubber liquid effluent.

(ii) A caustic strength monitoring device to monitor the caustic strength of the scrubber liquid effluent.

(iii) A conductivity monitoring device to monitor the conductivity of the scrubber liquid effluent.

(d) *Regenerative adsorber monitoring.* If you are using a regenerative adsorber to meet an emission limit in Table 1 or 2 to this subpart and you are required to use CPMS as specified in § 63.11925(c), you must install and operate the applicable monitoring equipment listed in paragraphs (d)(1) through (5) of this section, and comply with the requirements in paragraphs (d)(6) and (7) of this section. If the adsorption system water is wastewater as defined in § 63.12005, then it is subject to the requirements of § 63.11965.

(1) For non-vacuum regeneration systems, an integrating regeneration stream flow monitoring device having an accuracy of ±10 percent, capable of recording the total regeneration stream mass for each regeneration cycle. For non-vacuum regeneration systems, an integrating regeneration stream flow monitoring device capable of continuously recording the total regeneration stream mass flow for each regeneration cycle.

(2) For non-vacuum regeneration systems, an adsorber bed temperature monitoring device, capable of continuously recording the adsorber bed temperature after each regeneration and within 15 minutes of completing any temperature regulation (cooling or warming to bring bed temperature closer to vent gas temperature) portion of the regeneration cycle.

(3) For non-vacuum and non-steam regeneration systems, an adsorber bed temperature monitoring device capable of continuously recording the bed temperature during regeneration, except during any temperature regulating (cooling or warming to bring bed temperature closer to vent gas temperature) portion of the regeneration cycle.

(4) For a vacuum regeneration system, a pressure transmitter installed in the vacuum pump suction line capable of continuously recording the vacuum level for each minute during regeneration. You must establish a minimum target and a length of time at which the vacuum must be below the minimum target during regeneration.

(5) A device capable of monitoring the regeneration frequency (*i.e.*, operating time since last regeneration) and duration.

(6) You must perform a verification of the adsorber during each day of operation. The verification must be through visual observation or through an automated alarm or shutdown system that monitors and records system operational parameters. The verification must verify that the adsorber is operating with proper valve sequencing and cycle time.

(7) You must conduct weekly measurements of the carbon bed outlet volatile organic compounds concentration over the last 5 minutes of an adsorption cycle for each carbon bed. For regeneration cycles longer than 1 week, you must perform the measurement over the last 5 minutes of each adsorption cycle for each carbon bed. The outlet concentration of volatile organic compounds must be measured using a portable analyzer, in accordance with Method 21 at 40 CFR part 60, appendix A–7, for open-ended lines. Alternatively, outlet concentration of HAP(s) may be measured using chromatographic analysis using Method 18 at 40 CFR part 60, appendix A–6.

(e) *Non-regenerative adsorber monitoring.* If you are using a non-regenerative adsorber, or canister type system that is sent off site for regeneration or disposal, to meet an emission limit in Table 1 or 2 to this subpart and you are required to use CPMS as specified in § 63.11925(c), you must install a system of dual adsorber units in series and conduct the monitoring and bed replacement as specified in paragraphs (e)(1) through (4) of this section.

(1) Establish the average adsorber bed life by conducting daily monitoring of the outlet volatile organic compound or HAP concentration, as specified in this paragraph (e)(1), of the first adsorber bed in series until breakthrough occurs for the first three adsorber bed change-outs. The outlet concentration of volatile organic compounds must be measured using a portable analyzer, in accordance with Method 21 at 40 CFR part 60, appendix A–7, for open-ended lines. Alternatively, outlet concentration of HAP may be measured using chromatographic analysis using Method 18 at 40 CFR part 60, appendix A–6. Breakthrough of the bed is defined as the time when the level of HAP detected is at the highest concentration allowed to be discharged from the adsorber system.

(2) Once the average life of the bed is determined, conduct ongoing monitoring as specified in paragraphs (e)(2)(i) through (iii) of this section.

(i) Except as provided in paragraphs (e)(2)(ii) and (iii) of this section, conduct daily monitoring of the adsorber bed outlet volatile organic compound or HAP concentration, as specified in paragraph (e)(1) of this section.

(ii) You may conduct monthly monitoring if the adsorbent has more than 2 months of life remaining, as determined by the average primary adsorber bed life, established in paragraph (e)(1) of this section, and the date the adsorbent was last replaced.

(iii) You may conduct weekly monitoring if the adsorbent has more than 2 weeks of life remaining, as determined by the average primary adsorber bed life, established in paragraph (e)(1) of this section, and the date the adsorbent was last replaced.

(3) The first adsorber in series must be replaced immediately when breakthrough is detected between the first and second adsorber. The original second adsorber (or a fresh canister) will become the new first adsorber and a fresh adsorber will become the second adsorber. For purposes of this paragraph (e)(3), "immediately" means within 8 hours of the detection of a breakthrough for adsorbers of 55 gallons or less, and within 24 hours of the detection of a breakthrough for adsorbers greater than 55 gallons.

(4) In lieu of replacing the first adsorber immediately, you may elect to monitor the outlet of the second canister beginning on the day the breakthrough between the first and second canister is identified and each day thereafter. This daily monitoring must continue until the first canister is replaced. If the constituent being monitored is detected at the outlet of the second canister during this period of daily monitoring, both canisters must be replaced within 8 hours of the time of detection of

volatile organic compounds or HAP at 90 percent of the allowed level (90 percent of breakthrough definition).

(f) *Condenser monitoring.* If you are using a condenser to meet an emission limit in Table 1 or 2 to this subpart and you are required to use CPMS as specified in § 63.11925(c), you must install and operate a condenser exit gas temperature monitoring device.

(g) *Other control devices.* If you use a control device other than those listed in this subpart to comply with an emission limit in Table 1 or 2 to this subpart and you are required to use CPMS as specified in § 63.11925(c), you must comply with the requirements as specified in paragraphs (g)(1) and (2) of this section.

(1) Submit a description of the planned monitoring, recordkeeping, and reporting procedures. The Administrator will approve, deny or modify the proposed monitoring, reporting and recordkeeping requirements as part of the review of the plan or through the review of the permit application or by other appropriate means.

(2) You must establish operating limits for monitored parameters that are approved by the Administrator. To establish the operating limit, the information required in § 63.11935(d) must be submitted in the notification of compliance status report specified in § 63.11985(a).

(h) *Alternatives to monitoring requirements.* (1) You may request approval to use alternatives to the continuous operating parameter monitoring listed in this section, as specified in §§ 63.11985(c)(4) and 63.8.

(2) You may request approval to monitor a different parameter than those established in § 63.11935(d) or to set unique monitoring parameters, as specified in §§ 63.11985(c)(5) and 63.8. Until permission to use an alternative monitoring parameter has been granted by the Administrator, you remain subject to the requirements of this subpart.

§ 63.11945 What performance testing requirements must I meet for process vents?

(a) *General.* For each control device used to meet the emission limits for process vents in Table 1 or 2 to this subpart, you must conduct the initial and periodic performance tests required in § 63.11925(d) and (e) and as specified in § 63.11896 using the applicable test methods and procedures specified in Table 8 to this subpart and paragraphs (b) through (d) of this section.

(b) *Process operating conditions.* You must conduct performance tests under the conditions specified in paragraphs (b)(1) through (3) of this section, as applicable. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests. In all cases, a site-specific plan must be submitted to the Administrator for approval prior to testing in accordance with § 63.7(c). The test plan must include the emission profiles described in § 63.11925(g).

(1) *Continuous process vents.* For continuous process vents, you must conduct all performance tests at maximum representative operating conditions for the process. For continuous compliance, you must conduct subsequent performance tests within the range of operating limit(s) that were established for the control device during the initial or subsequent performance tests specified in § 63.11925(d) and (e). If an operating limit is a range, then you must conduct subsequent performance tests within the range of maximum or minimum operating limits for the control device, which result in highest emissions (*i.e.*, lowest emission reduction).

(2) *Batch process operations.* Testing must be conducted at absolute worst-case conditions or hypothetical worst-case conditions as specified in paragraph (c) of this section.

(3) *Combination of both continuous and batch unit operations.* You must conduct performance tests when the batch process vents are operating at absolute worst-case conditions or hypothetical worst-case conditions, as specified in paragraphs (c)(1) and (2) of this section, and at maximum representative operating conditions for the process. For continuous compliance, you must operate the control device as close as possible to your operating limit(s) for the control device established during the initial or subsequent performance tests specified in § 63.11925 (d) and (e). If an operating limit is a range, then you must operate the control device as close as possible to the maximum or minimum operating limit for the control device, whichever results in higher emissions (*i.e.*, lower emission reduction), unless the Administrator specifies or approves alternate operating conditions.

(c) *Batch worst-case conditions.* The absolute worst-case conditions for batch process operations must be characterized by the criteria presented in paragraph (c)(1) of this section. The hypothetical worst-case conditions for batch process operations must be characterized by the criteria presented in paragraph (c)(2) of this section.

(1) *Absolute worst-case conditions.* For batch process operations, absolute worst-case conditions are defined by the criteria presented in paragraph (c)(1)(i) of this section if the maximum load is the most challenging condition for the control device. Otherwise, absolute worst-case conditions are defined by the conditions in paragraph (c)(1)(ii) of this section. You must consider all relevant factors, including load and compound-specific characteristics in defining absolute worst-case conditions.

(i) A 1-hour period of time in which the inlet to the control device contains the highest HAP mass loading rate, in pounds per hour, capable of being vented to the control device. An emission profile as described in § 63.11925(g) must be used to identify the 1-hour period of maximum HAP loading.

(ii) The period of time when the HAP loading or stream composition (including non-HAP) is most challenging for the control device. These conditions include, but are not limited to the following:

(A) Periods when the stream contains the highest combined organic load, in pounds per hour, described by the emission profiles in § 63.11925(g).

(B) Periods when the streams contain HAP constituents that approach limits of solubility for scrubbing media.

(C) Periods when the streams contain HAP constituents that approach limits of adsorptivity for adsorption systems.

(2) *Hypothetical worst-case conditions.* For batch process operations, hypothetical worst-case conditions are simulated test conditions that, at a minimum, contain the highest hourly HAP load of emissions that would be predicted to be vented to the control device based on the emissions profiles described in paragraphs (c)(3)(ii) or (iii) of this section.

(3) *Emission profile.* For batch process operations, you must develop an emission profile for the vent to the control device that describes the characteristics of the vent stream at the inlet to the control device under worst-case conditions. The emission profile must be developed based on any one of the procedures described in paragraphs (c)(3)(i) through (iii) of this section.

(i) *Emission profile by process.* The emission profile must consider all batch emission episodes that could contribute to the vent stack for a period of time that is sufficient to include all processes venting to the stack and must consider production scheduling. The profile must describe the HAP load to the device that equals the highest sum of emissions from the episodes that can vent to the control device in any given hour.

Emissions per episode must be calculated using the procedures specified in § 63.11950. Emissions per episode must be divided by the duration of the episode only if the duration of the episode is longer than 1 hour.

(ii) *Emission profile by equipment.* The emission profile must consist of emissions that meet or exceed the highest emissions, in pounds per hour that would be expected under actual processing conditions. The profile must describe equipment configurations used to generate the emission events, volatility of materials processed in the equipment, and the rationale used to identify and characterize the emission events. The emissions may be based on using a compound more volatile than compounds actually used in the process(es), and the emissions may be generated from all equipment in the process(es) or only selected equipment.

(iii) *Emission profile by capture and control device limitation.* The emission profile must consider the capture and control system limitations and the highest emissions, in pounds per hour that can be routed to the control device, based on maximum flow rate and concentrations possible because of limitations on conveyance and control equipment (e.g., fans and lower explosive level alarms).

(d) *Concentration correction calculation.* If a combustion device is the control device and supplemental combustion air is used to combust the emissions, the concentration of total hydrocarbons, total organic HAP, vinyl chloride, and hydrogen chloride must be corrected as specified in paragraph (d)(1) or (2) of this section. If a control device other than a combustion device is used to comply with an outlet concentration emission limit for batch process vents, you must correct the actual concentration for supplemental gases as specified in paragraph (d)(3) of this section.

(1) Determine the concentration of total hydrocarbons, total organic HAP, vinyl chloride, or hydrogen chloride corrected to 3-percent oxygen (Cc) using Equation 1 of this section.

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2d}} \right) \qquad \text{(Eq. 1)}$$

Where:

C_c = Concentration of total hydrocarbons, total organic HAP, vinyl chloride, or hydrogen chloride corrected to 3-percent oxygen, dry basis, parts per million by volume.

C_m = Concentration of total hydrocarbons, total organic HAP, vinyl chloride, or hydrogen chloride, dry basis, parts per million by volume.

$\%O_{2d}$ = Concentration of oxygen, dry basis, percentage by volume.

(2) To determine the oxygen concentration, you must use the emission rate correction factor (or excess air), integrated sampling and analysis procedures of Method 3, 3A, or 3B at 40 CFR part 60, appendix A–2, or ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 63.14).

(3) Correct the measured concentration for supplemental gases using Equation 2 of this section. Process knowledge and representative operating data may be used to determine the fraction of the total flow due to supplemental gas.

$$C_a = C_m \left(\frac{Q_s + Q_a}{Q_a} \right) \qquad \text{(Eq. 2)}$$

Where:

C_a = Corrected outlet concentration of HAP, dry basis, parts per million by volume (ppmv).

C_m = Actual concentration of HAP measured at control device outlet, dry basis, ppmv.

Q_a = Total volumetric flow rate of all gas streams vented to the control device, except supplemental gases.

Q_s = total volumetric flow rate of supplemental gases.

§ 63.11950 What emissions calculations must I use for an emission profile?

When developing your emission profiles for batch process vents as required in § 63.11925(g), except as specified in paragraph (i) of this section, you must calculate emissions from episodes caused by vapor displacement, purging a partially filled vessel, heating, depressurization, vacuum operations, gas evolution, air drying, or empty vessel purging, using the applicable procedures in paragraphs (a) through (h) of this section.

(a) *Vapor displacement.* You must calculate emissions from vapor displacement due to transfer of material using Equation 1 of this section.

$$E = \left(\frac{V}{RT} \right) \sum_{i=1}^{n} P_i \left(MW_i \right) \qquad \text{(Eq. 1)}$$

Where:

E = Mass of HAP emitted.

V = Volume of gas displaced from the vessel.

R = Ideal gas law constant.

T = Temperature of the vessel vapor space; absolute.

P_i = Partial pressure of the individual HAP.

MW_i = Molecular weight of the individual HAP.

n = Number of HAP compounds in the emission stream.

i = Identifier for a HAP compound.

(b) *Gas sweep of a partially filled vessel.* You must calculate emissions from purging a partially filled vessel using Equation 2 of this section. The pressure of the vessel vapor space may be set equal to 760 millimeters of

mercury (mmHg). You must multiply the HAP partial pressure in Equation 2 of this section by a HAP-specific saturation factor determined in accordance with Equations 3 through 5 of this section. Solve Equation 3 of this section iteratively beginning with saturation factors (in the right-hand side of the equation) of 1.0 for each condensable compound. Stop iterating when the calculated saturation factors for all compounds are the same to two significant figures for subsequent iterations. Note that for multi-component emission streams, saturation factors must be calculated for all condensable compounds, not just the HAP.

$$E = \sum_{i=1}^{n} P_i MW_i \left(\frac{Vt}{RT}\right) \left(\frac{P_T}{P_T - \sum_{j=1}^{m}(P_j)}\right) \qquad \text{(Eq. 2)}$$

Where:

E = Mass of HAP emitted.
V = Purge flow rate of the noncondensable gas at the temperature and pressure of the vessel vapor space.
R = Ideal gas law constant.
T = Temperature of the vessel vapor space; absolute.
P_i = Partial pressure of the individual HAP at saturated conditions.
P_j = Partial pressure of individual condensable compounds (including HAP) at saturated conditions.
P_T = Pressure of the vessel vapor space.
MW_i = Molecular weight of the individual HAP.
t = Time of purge.
n = Number of HAP compounds in the emission stream.
i = Identifier for a HAP compound.
j = Identifier for a condensable compound.
m = Number of condensable compounds (including HAP) in the emission stream.

$$S_i = \frac{K_i A}{K_i A + V + \sum_{i=1}^{n} S_i V_i^{sat}} \qquad \text{(Eq. 3)}$$

$$V_i^{sat} = \frac{VP_i}{\left(P_T - \sum_{i=1}^{n} P_i\right)} \qquad \text{(Eq. 4)}$$

$$K_i = K_o \left(\frac{M_o}{M_i}\right)^{1/3} \qquad \text{(Eq. 5)}$$

Where:

S_i = Saturation factor for individual condensable compounds.
P_i = Partial pressure of individual condensable compounds at saturated conditions.
PT = Pressure of the vessel vapor space.
A = Surface area of liquid.
V = Purge flow rate of the noncondensable gas.
V_i^{sat} = Volumetric flow rate of individual condensable compounds at saturated vapor pressure.
K_i = Mass transfer coefficient of individual condensable compounds in the emission stream.
K_o = Mass transfer coefficient of reference compound (*e.g.*, 0.83 cm/s for water).
M_o = Molecular weight of reference compound (*e.g.*, 18.02 for water).
M_i = Molecular weight of individual condensable compounds in the emission stream.
n = Number of condensable compounds in the emission stream.

(c) *Heating.* You must calculate emissions caused by the heating of a vessel to a temperature lower than the boiling point using the procedures in paragraph (c)(1) of this section. If the contents of a vessel are heated to the

boiling point, you must calculate emissions using the procedures in paragraph (c)(2) of this section.

(1) If the final temperature to which the vessel contents are heated is lower than the boiling point of the HAP in the vessel, you must calculate the mass of HAP emitted per episode using Equation 6 of this section. The average gas space molar volume during the heating process is calculated using Equation 7 of this section. The difference in the number of moles of condensable in the vessel headspace between the initial and final temperatures is calculated using Equation 8 of this section.

$$E = MW_{HAP}\left[N_{avg} \ln\left[\frac{P_T - \sum_{i=1}^{n}\left(P_{i,1}\right)}{P_T - \sum_{i=1}^{n}\left(P_{i,2}\right)}\right] - \left(n_{i,2} - n_{i,1}\right)\right] \qquad \text{(Eq. 6)}$$

Where:

E = Mass of HAP vapor displaced from the vessel being heated.

N_{avg} = Average gas space molar volume during the heating process.

P_T = Total pressure in the vessel.

$P_{i,1}$ = Partial pressure of the individual HAP compounds at initial temperature (T_1).

$P_{i,2}$ = Partial pressure of the individual HAP compounds at final temperature (T_2).

MW_{HAP} = Average molecular weight of the HAP compounds calculated using Equation 13 of this section.

$n_{i,1}$ = Number of moles of condensable in the vessel headspace at initial temperature (T_1).

$n_{i,2}$ = Number of moles of condensable in the vessel headspace at final temperature (T_2).

n = Number of HAP compounds in the emission stream.

ln = Natural logarithm.

$$N_{avg} = \frac{VP_T}{2R}\left(\frac{1}{T_1} + \frac{1}{T_2}\right) \qquad \text{(Eq. 7)}$$

Where:

N_{avg} = Average gas space molar volume during the heating process.

V = Volume of free space in vessel.

P_T = Total pressure in the vessel.

R = Ideal gas law constant.

T_1 = Initial temperature of the vessel.

T_2 = Final temperature of the vessel.

$$\left(n_{i,2} - n_{i,1}\right) = \frac{V}{RT_2}\sum_{i=1}^{n}P_{i,2} - \frac{V}{RT_1}\sum_{i=1}^{n}P_{i,1} \qquad \text{(Eq. 8)}$$

Where:

V = Volume of free space in vessel.

R = Ideal gas law constant.

T_1 = Initial temperature in the vessel.

T_2 = Final temperature in the vessel.

$P_{i,1}$ = Partial pressure of the individual HAP compounds at T_1.

$P_{i,2}$ = Partial pressure of the individual HAP compounds at T_2.

n = Number of HAP compounds in the emission stream.

(2) If the final temperature to which the vessel contents are heated is at the boiling point or higher, you must calculate emissions using the procedure in paragraphs (c)(2)(i) and (ii) of this section.

(i) To calculate the emissions from heating to the boiling point use Equations 9, 10 and 11 of this section. (Note that $Pa_2 = 0$ in the calculation of $\Delta\eta$ in Equation 10 of this section.)

$$E = \Delta\eta \times \frac{\sum_{i=1}^{n}P_i MW_{HAP}}{P_T - \sum_{j=1}^{m}\left(P_j\right)} \qquad \text{(Eq. 9)}$$

Where:

E = Mass of HAP emitted.

$\Delta\eta$ = The number of moles of noncondensable displaced from the vessel, as calculated using Equation 10 of this section.

P_T = Pressure in the receiver.

P_i = Partial pressure of the individual HAP determined at the exit temperature of the condenser or at the conditions of the dedicated receiver.
P_j = Partial pressure of the individual condensable (including HAP) determined at the exit temperature of the condenser or at the conditions of the dedicated receiver.
n = Number of HAP compounds in the emission stream.
i = Identifier for a HAP compound.
j = Identifier for a condensable compound.
MW_{HAP} = The average molecular weight of HAP in vapor exiting the dedicated receiver, as calculated using Equation 11 of this section with partial pressures determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.
m = Number of condensable compounds (including HAP) in the emission stream.

$$\Delta\eta = \frac{V}{R}\left[\left(\frac{Pa_1}{T_1}\right) - \left(\frac{Pa_2}{T_2}\right)\right] \qquad \text{(Eq. 10)}$$

$$MW_{HAP} = \sum_{i=1}^{n} \frac{\left((P_i)_{T_1} + (P_i)_{T_2}\right) MW_i}{\sum_{i=1}^{n}\left((P_i)_{T_1} + (P_i)_{T_2}\right)} \qquad \text{(Eq. 11)}$$

Where:

$\Delta\eta$ = Number of moles of noncondensable gas displaced from the vessel.
V = Volume of free space in the vessel.
R = Ideal gas law constant.
T_1 = Initial temperature of vessel contents, absolute.
T_2 = Final temperature of vessel contents, absolute.
Pan = Partial pressure of noncondensable gas in the vessel headspace at initial (n=1) and final (n=2) temperature.
MW_{HAP} = The average molecular weight of HAP in vapor exiting the dedicated receiver.
$(P_i)Tn$ = Partial pressure of each HAP in the vessel headspace at initial (T_1) and final (T_2) temperature of the receiver.
MW_i = Molecular weight of the individual HAP.
n = Number of HAP compounds in the emission stream.
i = Identifier for a HAP compound.

(ii) While boiling, the vessel must be operated with a properly operated process condenser. An initial demonstration that a process condenser is properly operated must be conducted during the boiling operation and documented in the notification of compliance status report described in § 63.11985(a). You must either measure the liquid temperature in the receiver or the temperature of the gas stream exiting the condenser and show it is less than the boiling or bubble point of the HAP in the vessel; or perform a material balance around the vessel and condenser and show that at least 99 percent of the recovered HAP vaporized while boiling is condensed. This demonstration is not required if the process condenser is followed by a condenser acting as a control device or if the control device is monitored using a CEMS.

(d) *Depressurization.* You must calculate emissions from depressurization using Equation 12 of this section.

$$E = \frac{V}{RT} \times \ln\left(\frac{P_1 - \sum_{j=1}^{m}(P_j)}{P_2 - \sum_{j=1}^{m}(P_j)}\right) \times \sum_{i=1}^{n}(P_i)(MW_i) \qquad \text{(Eq. 12)}$$

Where:

E = Emissions.
V = Free volume in vessel being depressurized.
R = Ideal gas law constant.
T = Temperature of the vessel, absolute.
P_1 = Initial pressure in the vessel.
P_2 = Final pressure in the vessel.
P_j = Partial pressure of the individual condensable compounds (including HAP).
MW_i = Molecular weight of the individual HAP compounds.
n = Number of HAP compounds in the emission stream.
m = Number of condensable compounds (including HAP) in the emission stream.
i = Identifier for a HAP compound.
j = Identifier for a condensable compound.
ln = Natural logarithm.

(e) *Vacuum systems.* You must calculate emissions from vacuum systems using Equation 13 of this section if the air leakage rate is known or can be approximated. The receiving vessel is part of the vacuum system for purposes of this subpart.

$$E = \frac{(La)(t)}{MW_{nc}} \left(\frac{\sum_{i=1}^{n} P_i MW_i}{P_T - \sum_{j=1}^{m} (P_j)} \right) \quad \text{(Eq. 13)}$$

Where:

E = Mass of HAP emitted.

P_T = Absolute pressure of receiving vessel or ejector outlet conditions, if there is no receiver.

P_i = Partial pressure of the HAP at the receiver temperature or the ejector outlet conditions.

P_j = Partial pressure of condensable (including HAP) at the receiver temperature or the ejector outlet conditions.

La = Total air leak rate in the system, mass/time.

MW_{nc} = Molecular weight of noncondensable gas.

t = Time of vacuum operation.

MWi = Molecular weight of the individual HAP in the emission stream, with HAP partial pressures calculated at the temperature of the receiver or ejector outlet, as appropriate.

(f) *Gas evolution.* You must calculate emissions from gas evolution using Equation 13 in paragraph (e) of this section with mass flow rate of gas evolution, Wg, substituted for La.

(g) *Air drying.* You must calculate emissions from air drying using Equation 14 of this section:

$$E = B \times \left(\frac{PS_1}{100 - PS_1} - \frac{PS_2}{100 - PS_2} \right) \quad \text{(Eq. 14)}$$

Where:

E = Mass of HAP emitted.

B = Mass of dry solids.

PS_1 = HAP in material entering dryer, weight percent.

PS_2 = HAP in material exiting dryer, weight percent.

(h) *Empty vessel purging.* You must calculate emissions from empty vessel purging using Equation 15 of this section (Note: The term e-Ft/v can be assumed to be 0):

$$E = \left(\frac{V}{RT} \times \left[\sum_{i=1}^{n} (P_i)(MW_i) \right] (1 - e^{-Ft/v}) \right) \quad \text{(Eq. 15)}$$

Where:

V = Volume of empty vessel.

R = Ideal gas law constant.

T = Temperature of the vessel vapor space; absolute.

P_i = Partial pressure of the individual HAP at the beginning of the purge.

MW_i = Molecular weight of the individual HAP.

F = Flow rate of the purge gas.

t = Duration of the purge.

n = Number of HAP compounds in the emission stream.

i = Identifier for a HAP compound.

(i) *Engineering assessments.* You must conduct an engineering assessment to calculate HAP emissions or emission episodes from each process vent that are not due to vapor displacement, partially filled vessel purging, heating, depressurization, vacuum operations, gas evolution, air drying or empty vessel purging. An engineering assessment may also be used to support a finding that the emissions estimation equations in this section are inappropriate. All data, assumptions and procedures used in the engineering assessment must be documented, are subject to preapproval by the Administrator, and must be reported in the batch precompliance report. An engineering assessment should include, but is not limited to, the items listed in paragraphs (i)(1) through (4) of this section.

(1) Previous test results provided the tests are representative of current operating practices at the process unit.

(2) Bench-scale or pilot-scale test data representative of the process under representative operating conditions.

(3) Maximum flow rate, HAP emission rate, concentration, or other relevant parameter specified or implied within a permit limit applicable to the process vent.

(4) Design analysis based on accepted chemical engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to the following:

(i) Use of material balances based on process stoichiometry to estimate maximum organic HAP concentrations.

(ii) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities.

(iii) Estimation of HAP concentrations based on saturation conditions.

§ 63.11955 What are my initial and continuous compliance requirements for other emission sources?

(a) Before opening any process component (including pre-polymerization reactors used in the manufacture of bulk resins) for any reason, the quantity of vinyl chloride must be reduced to an amount that occupies a volume of no more than 2.0 percent of the component's or equipment's containment volume, or 25 gallons, whichever is larger, at standard temperature and pressure.

(b) Before opening a polymerization reactor for any reason, the quantity of vinyl chloride is not to exceed 0.04 pounds per ton of PVC product, with the product determined on a dry solids basis.

(c) Any gas or vapor HAP removed from a process component in

accordance with paragraphs (a) and (b) of this section must be vented to a closed vent system and control device meeting the requirements of §§ 63.11925 through 63.11950.

(d) Each gasholder in vinyl chloride service must meet the requirements of paragraphs (d)(1) through (3) of this section.

(1) Each gasholder must be vented to a closed vent system and control device meeting the requirements of §§ 63.11925 through 63.11950.

(2) Each gasholder must operate with one or more of the following installed on the water seal to reduce emissions:

(i) Floating balls;

(ii) Hollow floating disks;

(iii) Oil layer; and/or

(iv) Floating mats.

(3) Each gasholder must have established operating procedures that include provisions for ensuring that the requirements of paragraph (d)(2) of this section are met at all times except during periods of maintenance or repair. The standard operating procedures must be developed and implemented and made available to the Administrator upon request.

§ 63.11956 What are my compliance requirements for ambient monitoring?

You must operate a reliable and accurate vinyl chloride monitoring system for detection of major leaks and identification of the general area of the affected source where a leak is located. A vinyl chloride monitoring system means a device which obtains air samples from one or more points on a continuous sequential basis and analyzes the samples with gas chromatography or, if you assume that all hydrocarbons measured are vinyl chloride, analyzes the samples with infrared spectrophotometry, flame ion detection, or an equivalent or alternative method. You must operate the vinyl chloride monitoring system according to a program that you develop for your affected source. You must submit a description of the program to the Administrator within 45 days of your compliance date, unless a waiver of compliance is granted by the Administrator, or the program has been approved and the Administrator does not request a review of the program. Approval of a program will be granted by the Administrator provided the Administrator finds:

(a) The location and number of points to be monitored and the frequency of monitoring provided for in the program are acceptable when they are compared with the number of pieces of equipment in vinyl chloride service and size and physical layout of the affected source.

(b) It contains a definition of leak which is acceptable when compared with the background concentrations of vinyl chloride in the areas of the plant to be monitored by the vinyl chloride monitoring system. Measurements of background concentrations of vinyl chloride in the areas of the plant to be monitored by the vinyl chloride monitoring system are to be included with the description of the program. The definition of leak for a given plant may vary among the different areas within the plant and is also to change over time as background concentrations in the plant are reduced.

(c) It contains an acceptable plan of action to be taken when a leak is detected.

(d) It provides for an acceptable calibration and maintenance schedule for the vinyl chloride monitoring system and portable hydrocarbon detector. For the vinyl chloride monitoring system, a daily span check must be conducted with a concentration of vinyl chloride equal to the concentration defined as a leak according to paragraph (b) of this section. The calibration must be done with either:

(1) A calibration gas mixture prepared from the gases specified in sections 7.2.1 and 7.2.2 of Method 106 at 40 CFR part 61, appendix B, and in accordance with section 10.1 of Method 106, or

(2) A calibration gas cylinder standard containing the appropriate concentration of vinyl chloride. The gas composition of the calibration gas cylinder standard must have been certified by the manufacturer. The manufacturer must have recommended a maximum shelf life for each cylinder so that the concentration does not change greater than ±5 percent from the certified value. The date of gas cylinder preparation, certified vinyl chloride concentration, and recommended maximum shelf life must have been affixed to the cylinder before shipment from the manufacturer to the buyer. If a gas chromatograph is used as the vinyl chloride monitoring system, these gas mixtures may be directly used to prepare a chromatograph calibration curve as described in Sections 8.1 and 9.2 of Method 106. The requirements in Sections 7.2.3.1 and 7.2.3.2 of Method 106 for certification of cylinder standards and for establishment and verification of calibration standards are to be followed.

§ 63.11960 What are my initial and continuous compliance requirements for stripped resin?

(a) *Emission limits.* You must meet the applicable vinyl chloride and total non-vinyl chloride organic HAP emission limits for stripped resin specified in Table 1 or 2 to this subpart.

(b) *Determination of total non-vinyl chloride organic HAP.* You must develop a facility-specific list of HAP that are expected to be present in each grade of resin produced by your PVCPU. This list must be continuously updated and must be available for inspection by the Administrator. This list must include the identification of each grade of resin produced, each HAP expected to be present in that grade of resin, and the CAS number for each HAP.

(1) For the purposes of demonstrating initial and continuous compliance as required in paragraphs (c) and (d) of this section, you must meet the requirements specified in paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(i) You must analyze each resin sample for all Table 10 HAP using the test methods specified in paragraph (e) of this section.

(ii) You must also analyze each resin sample for any HAP that are not a Table 10 HAP but are expected to be present in that resin sample based on your facility-specific list of HAP using the appropriate test method specified in paragraph (e) of this section.

(2) [Reserved]

(c) *Demonstration of initial compliance.* You must demonstrate initial compliance for each resin stripper or for each group of resin strippers used to process the same resin type.

(1) You must conduct an initial performance test for the resin stripper, measuring the concentration of vinyl chloride and total non-vinyl chloride organic HAP in the stripped resin at the outlet of each resin stripper as specified in paragraphs (c)(1)(i) through (iv) of this section.

(i) Use the test method(s) and procedures specified in paragraph (e) of this section.

(ii) Collect samples when the PVCPU is producing the resin grade of which you manufacture the most, based on the total mass per resin grade of a given resin type produced in the 12 months preceding the sampling event.

(iii) For continuous processes, during a 24-hour sampling period, for each resin grade produced, collect 1 grab sample at intervals of 8 hours or per grade of PVC produced, whichever is more frequent. Each sample must be taken as the resin flows out of the stripper.

(iv) For batch processes, during a 24-hour sampling period, for each batch of each resin grade produced, collect 1 grab sample for each batch. Each sample must be taken immediately following

the completion of the stripping operation.

(2) Demonstrate initial compliance with the vinyl chloride and total non-vinyl chloride organic HAP emission limits in Table 1 or 2 to this subpart as specified in paragraphs (c)(2)(i) and (ii) of this section.

(i) Calculate the 24-hour arithmetic average vinyl chloride and total non-vinyl chloride organic HAP concentrations for each stripper for each resin grade produced during the 24-hour sampling period, using the vinyl chloride and non vinyl-chloride HAP concentrations measured for the grab samples collected as specified in paragraph (c)(1)(iii) and (iv) of this section and using the calculation procedure specified in paragraph (f) of this section to determine the total non-vinyl chloride organic HAP concentration of each sample.

(ii) Demonstrate compliance with the vinyl chloride and total non-vinyl chloride organic HAP emission limits in Table 1 or 2 to this subpart based on the 24-hour arithmetic average concentrations calculated in either paragraph (c)(2)(ii)(A) or (B) of this section.

(A) If more than one resin grade was produced during the 24-hour sampling period, use Equation 1 of this section to calculate the 24-hour grade weighted arithmetic average vinyl chloride and total non-vinyl chloride organic HAP concentrations for each stripper, or for each group of strippers used to process the same type of resin, using the 24-hour average vinyl chloride and total non-vinyl chloride organic HAP concentrations calculated in paragraph (c)(2)(i) of this section and the mass of each resin grade produced during the 24-hour sampling period.

$$A_T = \frac{\Sigma_{i=1}^{n} P_{Gi} C_{Gi}}{Q_T} = \frac{P_{G_1} C_{G_1} + P_{G_2} C_{G_2} + \ \ldots \ + P_{Gn} C_{Gn}}{Q_T} \qquad \text{(Eq. 1)}$$

Where:

A_T = 24-hour average concentration of resin type T, parts per million by weight (dry basis).

P_{Gi} = Production of resin grade G_i, pounds.

C_{Gi} = 24-hour average concentration of vinyl chloride or total non-vinyl chloride organic HAP in resin grade G_i, ppmw.

Q_T = Total production of resin type T over the 24-hour sampling period, pounds.

(B) If only one resin grade was produced during the 24-hour sampling event, use the 24-hour arithmetic average vinyl chloride and total non-vinyl chloride organic HAP concentrations for the one resin grade calculated as specified in paragraph (c)(2)(i) of this section for each stripper or calculate the 24-hour arithmetic average vinyl chloride and total non-vinyl chloride organic HAP concentrations for all strippers used to process the one grade of resin.

(d) *Demonstration of continuous compliance.* You must demonstrate continuous compliance for each resin stripper or for each group of resin strippers used to process the same resin type.

(1) On a daily basis, you must measure the concentration of vinyl chloride in stripped resin using the test method(s) and procedures specified in paragraph (e) of this section, and the procedures specified in paragraphs (c)(1)(iii) and (iv) of this section.

(2) On a monthly basis, you must measure the concentration of total non-vinyl chloride organic HAP in stripped resin using the test method(s) and procedures specified in paragraph (e) of this section, and the procedures specified in paragraphs (c)(1)(iii) and (iv) of this section.

(3) You must demonstrate continuous compliance with the vinyl chloride and total non-vinyl chloride organic HAP emission limit for stripped resin in Table 1 or 2 to this subpart as specified in paragraphs (c)(2)(i) and (ii) of this section.

(e) *Test methods and procedures for determining concentration of vinyl chloride and total non-vinyl chloride organic HAP.* You must determine the concentration of vinyl chloride and total non-vinyl chloride organic HAP using the test methods and procedures specified in paragraphs (e)(1) through (3) of this section. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(1) For measuring total non-vinyl chloride organic HAP, you must use the methods specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) SW–846–8260B (incorporated by reference, see § 63.14) for analysis of volatile organic compounds listed in Table 10 of this subpart.

(ii) SW–846–8270D (incorporated by reference, see § 63.14) for analysis of semivolatile organic compounds listed in table 10 of this subpart.

(iii) SW–846–8315A (incorporated by reference, see § 63.14) for analysis of aldehyde compounds listed in table 10 of this subpart.

(iv) SW–846–8015C (incorporated by reference, see § 63.14) for analysis of alcohol compounds listed in table 10 of this subpart.

(2) For measuring vinyl chloride, you must use Method 107 at 40 CFR part 61, appendix B.

(3) When using the methods specified in paragraphs (e)(1) and (2) of this section, for sample collection, preservation, transport, and analysis, you must minimize loss of HAP and maintain sample integrity.

(f) *Method for calculating total non-vinyl chloride organic HAP concentration.* For each stripped resin sample analyzed using the methods specified in paragraph (e) of this section, calculate the sum of the measured concentrations of each HAP analyzed as required in paragraphs (b)(1)(i) and (b)(1)(ii) of this section by using Equation 2 to this section.

$$C_{TNVCH} = \sum_{i=1}^{n} C_i \qquad \text{(Eq. 2)}$$

Where:

C_{TNVCH} = Concentration of total non-vinyl chloride organic HAP compounds in the stripped resin sample, in parts per million by weight (ppmw).

C_i = Concentration of individual HAP present in the stripped resin sample analyzed pursuant to paragraphs (b)(1)(i) and (b)(1)(ii) of this section excluding vinyl chloride, in ppmw, where a value of zero should be used for any HAP concentration that is below the detection limit.

§ 63.11965 What are my general compliance requirements for wastewater?

(a) The concentration of vinyl chloride and total non-vinyl chloride organic HAP in each process wastewater stream containing greater than the limits specified in Table 1 or 2 to this subpart, measured immediately as it leaves a piece of process equipment and before being mixed with any other process wastewater stream, must be reduced to the limits specified in Table 1 or 2 to this subpart. The applicable limits in

Table 1 or 2 to this subpart must be met before the process wastewater stream is mixed with any other process wastewater stream containing vinyl chloride or total non-vinyl chloride organic HAP concentrations less than the applicable limits specified in Table 1 or 2 to this subpart, before being exposed to the atmosphere, and before being discharged from the affected source.

(b) *Initial determination of process wastewater streams that need to be treated.* You must determine which process wastewater streams require treatment as specified in paragraphs (b)(1) and (2) of this section and meet the requirements of paragraphs (c) and (d) of this section.

(1) You must collect process wastewater samples as specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) For treated process wastewater streams, you must collect process wastewater samples at the outlet of the treatment process and before the process wastewater stream is mixed with any other process wastewater stream containing vinyl chloride or total non-vinyl chloride organic HAP concentrations less than the applicable limits specified in Table 1 or 2 to this subpart, before being exposed to the atmosphere, and before being discharged from the affected source.

(ii) For untreated process wastewater streams, you must collect process wastewater samples at the location immediately as the stream leaves a piece of process equipment, before being mixed with any other process stream or process wastewater stream, before being exposed to the atmosphere, and before being discharged from the affected source.

(2) You must measure the concentration of vinyl chloride and total non-vinyl chloride organic HAP using the test methods and procedures specified in § 63.11980.

(c) *Requirements for process wastewater streams that must be treated.* Each process wastewater stream that has a vinyl chloride or total non-vinyl chloride organic HAP concentration equal to or greater than the limits specified in Table 1 or 2 to this subpart, determined pursuant to paragraph (a) of this section must be treated to reduce the concentration of vinyl chloride or total non-vinyl chloride organic HAP to below the applicable limits specified in Table 1 or 2 to this subpart. You must route wastewater streams through hard-piping to the treatment process and route the vent stream from the treatment process to a closed vent system and control device meeting the requirements of §§ 63.11925 through 63.11950. You must also meet the initial and continuous compliance requirements specified in § 63.11970(a) and § 63.11975.

(d) *Requirements for process wastewater streams that do not need to be treated.* For each process wastewater stream that has a vinyl chloride or total non-vinyl chloride organic HAP concentration less than the limits specified in Table 1 or 2 to this subpart, determined pursuant to paragraph (a) of this section, you must meet the initial and continuous compliance requirements specified in §§ 63.11970(b) and 63.11975(c).

(e) *Maintenance wastewater.* You must comply with the requirements specified in § 63.105 of subpart F of this part.

(f) *Determination of total non-vinyl chloride organic HAP.* You must develop a facility-specific list of HAP that are expected to be present in each process wastewater stream at your PVCPU. This list must be continuously updated and must be available for inspection by the Administrator. This list must include the identification of each HAP expected to be present in each process wastewater stream, and the CAS number for each HAP.

(1) For the purposes of demonstrating initial and continuous compliance as required in §§ 63.11970 and 63.11975 of this subpart, you must meet the requirements specified in paragraphs (f)(1)(i) and (ii) of this section.

(i) You must analyze each process wastewater sample for all HAP listed in Table 10 to this subpart using the test methods specified in § 63.11980(a)(2) and (3).

(ii) You must also analyze each process wastewater sample for any HAP that are not listed in Table 10 to this subpart but are expected to be present in that sample based on your facility-specific list of HAP using the appropriate test method specified in § 63.11980(a)(2).

(2) [Reserved]

§ 63.11970 What are my initial compliance requirements for process wastewater?

(a) *Demonstration of initial compliance for process wastewater streams that must be treated.* For each process wastewater stream that must be treated as specified in § 63.11965(b) and (c), you must conduct an initial performance test for the wastewater treatment process, measuring the concentration of vinyl chloride and total non-vinyl chloride organic HAP in the wastewater stream at the outlet of the wastewater treatment process before the wastewater is exposed to the atmosphere, mixed with any other process stream, and before being discharged from the affected facility, using the test method(s) and procedures specified in § 63.11980(a).

(b) *Demonstration of initial compliance for process wastewater streams that are not required to be treated.* For each process wastewater stream that has a vinyl chloride or total non-vinyl chloride organic HAP concentration less than the limits specified in Tables 1 or 2 to this subpart, you must use the measurement specified in § 63.11965(b)(1)(ii) to demonstrate initial compliance.

§ 63.11975 What are my continuous compliance requirements for process wastewater?

(a) For each process wastewater stream that must be treated to reduce the concentration of vinyl chloride or total non-vinyl chloride organic HAP as specified in § 63.11965(b) and (c), you must demonstrate continuous compliance as specified in paragraph (b) of this section. For each process wastewater stream for which you initially determine in § 63.11970(b) that treatment is not required to reduce either vinyl chloride or total non-vinyl chloride organic HAP concentration, you must demonstrate continuous compliance as specified in paragraph (c) of this section.

(b) For each process wastewater stream that must be treated according to § 63.11965(b), you must demonstrate continuous compliance with the emission limits for vinyl chloride and total non-vinyl chloride organic HAP specified in Table 1 or 2 to this subpart by following the procedures specified in paragraphs (b)(1) and (2) of this section.

(1) Following your demonstration of initial compliance in § 63.11970(a), make monthly measurements of the vinyl chloride and total non-vinyl chloride organic HAP concentrations using the procedures and methods specified in § 63.11965(b)(1) and (2).

(2) You must demonstrate continuous compliance with the emission limits in Table 1 or 2 to this subpart on a monthly basis, using the monthly concentration measurement specified in paragraph (b)(1) of this section.

(c) For each wastewater stream for which you initially determine in § 63.11970(b) that treatment is not required to reduce the vinyl chloride or total non-vinyl chloride organic HAP concentration, you must demonstrate continuous compliance as specified in paragraphs (c)(1) and (2) of this section.

(1) Conduct annual performance tests, measuring the vinyl chloride and total

non-vinyl chloride organic HAP concentrations using the procedures and methods specified in § 63.11965(b)(1) and (2).

(2) If any annual performance test conducted as specified in paragraph (c)(1) of this section results in a concentration of vinyl chloride or total non-vinyl chloride organic HAP in the process wastewater stream that is greater than or equal to the emission limits in Table 1 or 2 to this subpart, then you must meet the requirements of § 63.11965(c) and you must demonstrate initial and continuous compliance as specified in § 63.11970 and this section.

§ 63.11980 What are the test methods and calculation procedures for process wastewater?

(a) *Performance test methods and procedures.* You must determine the concentration of vinyl chloride and total non-vinyl chloride organic HAP using the test methods and procedures specified in paragraphs (a)(1) through (4) of this section. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(1) You must conduct performance tests during worst-case operating conditions for the PVCPU when the process wastewater treatment process is operating as close as possible to maximum operating conditions. If the wastewater treatment process will be operating at several different sets of operating conditions, you must supplement the testing with additional testing, modeling or engineering assessments to demonstrate compliance with the emission limits.

(2) For measuring total non-vinyl chloride organic HAP, you must conduct sampling and analysis using the methods specified in paragraphs (a)(2)(i) through (iv) of this section.

(i) SW–846–8260B (incorporated by reference, see § 63.14) for analysis of volatile organic compounds listed in Table 10 of this subpart.

(ii) SW–846–8270D (incorporated by reference, see § 63.14) for analysis of semivolatile organic compounds.

(iii) SW–846–8315A (incorporated by reference, see § 63.14) for analysis of aldehyde compounds.

(iv) SW–846–8015C (incorporated by reference, see § 63.14) for analysis of alcohol compounds.

(3) For measuring vinyl chloride, you must use Method 107 at 40 CFR part 61, appendix B.

(4) When using the methods in paragraphs (a)(2) and (3) of this section, you must meet the requirements in paragraphs (a)(4)(i) through (iii) of this section.

(i) Sample collection may consist of grab or composite samples.

(ii) Samples must be taken before the process wastewater stream is exposed to the atmosphere.

(iii) You must ensure that sample collection, preservation, transport, and analysis minimizes loss of HAP and maintains sample integrity.

(b) Method for calculating total non-vinyl chloride organic HAP concentration. For each process wastewater stream analyzed using the methods specified in paragraph (a) of this section, calculate the sum of the measured concentrations of each HAP analyzed as required in § 63.11965(f)(1) by using Equation 1 to this section.

$$C_{TNVCH} = \sum_{i=1}^{n} C_i \qquad \text{(Eq. 1)}$$

Where:

C_{TNVCH} = Concentration of total non-vinyl chloride organic HAP, in parts per million by weight (ppmw).

C_i = Concentration of individual HAP present in the sample analyzed pursuant to § 63.11965(f)(1) excluding vinyl chloride, in ppmw, where a value of zero should be used for any HAP concentration that is below the detection limit.

Notifications, Reports and Records

§ 63.11985 What notifications and reports must I submit and when?

In addition to the notifications and reports required in subpart A of this part, as specified in Table 4 to this subpart, you must submit the additional information and reports specified in paragraphs (a) through (c) of this section, as applicable.

(a) *Notification of compliance status.* When submitting the notification of compliance status required in § 63.9(h), you must also include the information specified in paragraphs (a)(1) through (9) of this section, as applicable.

(1) You must include an identification of the storage vessels subject to this subpart, including the capacity and liquid stored for each vessel. You must submit the information specified in paragraph (a)(2) of this section for each pressure vessel.

(2) You must include the information specified in § 63.1039(a) for equipment leaks.

(3) You must include an identification of the heat exchange systems that are subject to the requirements of this subpart.

(4) You must include the operating limit for each monitoring parameter identified for each control device used to meet the emission limits in Table 1 or 2 to this subpart, as determined pursuant to § 63.11935(d). This report must include the information in § 63.11935(d)(2), as applicable.

(5) You must include the records specified in paragraphs (a)(5)(i) through (iii) of this section, as applicable, for process vents.

(i) You must include the performance test records specified in § 63.11990(f)(1), as applicable. These reports must include one complete test report for each test method used for each process vent. A complete test report must include a brief process description, sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations and any other information required by the test method. For additional tests performed for the same kind of emission point using the same method, the results and any other information required in applicable sections of this subpart must be submitted, but a complete test report is not required.

(ii) You must include the information specified in paragraphs (a)(5)(ii)(A) through (C) of this section for batch process vent operations.

(A) Descriptions of worst-case operating and/or testing conditions for control devices including results of emissions profiles.

(B) Calculations used to demonstrate initial compliance according to §§ 63.11945 and 63.11950, including documentation of the proper operation of a process condenser(s) as specified in § 63.11950(c)(2)(ii).

(C) Data and rationale used to support an engineering assessment to calculate emissions in accordance with § 63.11950(i).

(iii) If you use a control device other than those listed in § 63.11940 for your process vent, then you must include a description of the parameters to be monitored to ensure the control device is operated in conformance with its design and achieves the specified emission limitation; an explanation of the criteria used to select the parameter; and a description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device, the schedule for this demonstration, and a statement that you will establish an operating limit for the

monitored parameter as specified in paragraph (a)(4) of this section.

(6) [Reserved]

(7) You must include the records specified in paragraphs (a)(7)(i) and (ii) of this section, as applicable, for resin strippers.

(i) You must include an identification of each resin stripper and resin type subject to the requirements of this subpart.

(ii) You must include results of the initial testing used to determine initial compliance with the stripped resin limits in Table 1 or 2 to this subpart.

(8) You must include the records specified in paragraphs (a)(8)(i) and (ii) of this section, as applicable, for process wastewater.

(i) You must include an identification of each process wastewater stream subject to the requirements of this subpart, and the results of your determination for each stream as to whether it must be treated to meet the limits of Table 1 or 2 to this subpart. You must also include a description of the treatment process to be used for each process wastewater stream that requires treatment.

(ii) You must include results of the initial sampling used to determine initial compliance with the vinyl chloride and total non-vinyl chloride organic HAP limits in Table 1 or 2 to this subpart.

(9) You must include a certification of compliance, signed by a responsible official, as applicable that states the following:

(i) "This facility complies with the requirements in this subpart for storage vessels."

(ii) "This facility complies with the requirements in this subpart for equipment leaks."

(iii) "This facility complies with the requirements in this subpart for heat exchange systems."

(iv) "This facility complies with the requirements in this subpart for HAP emissions from process vents."

(v) "This facility complies with the requirements in this subpart for other emission sources."

(vi) "This facility complies with the requirements in this subpart for the stripped resin."

(vii) "This facility complies with the requirements in this subpart for wastewater."

(b) *Compliance reports.* When submitting the excess emissions and continuous monitoring system performance report and summary report required in § 63.10(e)(3), you must also include the information specified in paragraphs (b)(1) through (12) of this section, as applicable. This report is referred to in this subpart as your compliance report.

(1) You must include a copy of the inspection record specified in § 63.11990(b)(2) for each storage vessel when a defect, failure, or leak is detected. You must also include a copy of the applicable information specified in § 63.1039(b)(5) through (8) of subpart UU of this part for each pressure vessel.

(2) You must include the information specified in § 63.1039(b) for equipment leaks, except for releases from pressure relief devices. For any releases from pressure relief devices, you must submit the report specified in paragraph (c)(7) of this section instead of the information specified in § 63.1039(b)(4) of subpart UU of this part.

(3) You must include the information specified in paragraphs (b)(3)(i) through (vi) of this section for heat exchange systems.

(i) The number of heat exchange systems in HAP service.

(ii) The number of heat exchange systems in HAP service found to be leaking.

(iii) A summary of the monitoring data that indicate a leak, including the number of leaks determined to be equal to or greater than the leak definition.

(iv) If applicable, the date a leak was identified, the date the source of the leak was identified and the date of repair.

(v) If applicable, a summary of each delayed repair, including the original date and reason for the delay and the date of repair, if repaired during the reporting period.

(vi) If applicable, an estimate of total VOC or vinyl chloride emissions for each delayed repair over the reporting period.

(4) You must include the records specified in paragraphs (b)(4)(i) through (iii) of this section, as applicable, for process vents, resin strippers, and wastewater.

(i) Deviations using CEMS or CPMS. For each deviation from an emission limit or operating limit where a CEMS or CPMS is being used to comply with the process vent emission limits in Table 1 or 2 to this subpart, you must include the information in paragraphs (b)(4)(i)(A) through (E) of this section.

(A) For CEMS, the 3-hour block average value calculated for any period when the value is higher than an emission limit in Table 1 or 2 to this subpart or when the value does not meet the data availability requirements defined in § 63.11890(c).

(B) For CPMS, the average value calculated for any day (based on the data averaging periods for compliance specified in Table 5 to this subpart) that does not meet your operating limit established according to § 63.11935(d) or that does not meet the data availability requirements specified in § 63.11890(c).

(C) The cause for the calculated emission level or operating parameter level to not meet the established emission limit or operating limit.

(D) For deviations caused by lack of monitoring data, the duration of periods when monitoring data were not collected.

(E) Operating logs of batch process operations for each day during which the deviation occurred, including a description of the operating scenario(s) during the deviation.

(ii) New operating scenario. Include each new operating scenario that has been operated since the time period covered by the last compliance report and has not been submitted in the notification of compliance status report or a previous compliance report. For each new operating scenario, you must provide verification that the operating conditions for any associated control or treatment device have not been exceeded and constitute proper operation for the new operating scenario. You must provide any required calculations and engineering analyses that have been performed for the new operating scenario. For the purposes of this paragraph (b)(4)(ii), a revised operating scenario for an existing process is considered to be a new operating scenario when one or more of the data elements listed in § 63.11990(e)(4) have changed.

(iii) Process changes. You must document process changes, or changes made to any of the information submitted in the notification of compliance status report or a previous compliance report, that is not within the scope of an existing operating scenario, in the compliance report. The notification must include all of the information in paragraphs (b)(4)(iii)(A) through (C) of this section.

(A) A description of the process change.

(B) Revisions to any of the information reported in the original notification of compliance status report as provided in paragraph (a) of this section.

(C) Information required by the notification of compliance status report, as provided in paragraph (a) of this section, for changes involving the addition of processes, components, or equipment at the affected source.

(5) You must submit the applicable information specified in paragraphs (b)(5)(i) through (iii) of this section for process vents.

(i) For catalytic thermal oxidizers for which you have selected the alternative monitoring specified in § 63.11940(b)(3), results of the annual catalyst sampling and inspections required by § 63.11940(b)(3)(i) and (ii) including any subsequent corrective actions taken.

(ii) For regenerative adsorbers, results of the adsorber bed outlet volatile organic compounds concentration measurements specified in § 63.11940(d)(7).

(iii) For non-regenerative adsorbers, results of the adsorber bed outlet volatile organic compounds concentration measurements specified in § 63.11940(e)(2).

(6) You must include the records specified in § 63.11990(j) for other emission sources.

(7) For resin stripper operations, you must include results of daily vinyl chloride and monthly total non-vinyl chloride organic HAP concentration results for each resin type produced within the PVCPU that did not meet the stripped resin emission limits in Table 1 or 2 to this subpart, as applicable.

(8) You must include the information specified in paragraphs (b)(8)(i) and (ii) of this section for your wastewater streams.

(i) Results of daily vinyl chloride and monthly total non-vinyl chloride organic HAP concentration results for each process wastewater stream discharged from the affected source that did not meet the process wastewater emission limits in Tables 1 or 2 to this subpart.

(ii) If you must comply with § 63.11965, then you must include any other applicable information that is required by the reporting requirements specified in § 63.146.

(9) For closed vent systems subject to the requirements of § 63.11930, you must include the information specified in paragraphs (b)(9)(i) through (iv) of this section, as applicable.

(i) As applicable, records as specified in § 63.11930(g)(1)(i) for all times when flow was detected in the bypass line, the vent stream was diverted from the control device, or the flow indicator was not operating.

(ii) As applicable, records as specified in § 63.11930(g)(1)(ii) for all occurrences of all periods when a bypass of the system was indicated (the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out, and records of any car-seal that has been broken).

(iii) Records of all times when monitoring of the system was not performed as specified in § 63.11930(d) and (e), or repairs were not performed as specified in § 63.11930(f), or records were not kept as specified in § 63.11930(g)(2).

(iv) Records of each time an alarm on a closed vent system operating in vacuum service is triggered as specified in § 63.11930(h) including the cause for the alarm and the corrective action taken.

(10) Closed vent system in vacuum service, bypass deviation, or pressure vessel closure device deviation report. If any pressure vessel closure device or closed vent system that contains a bypass has directly discharged to the atmosphere, or any closed vent system that is designed to be in vacuum service and is operating and but not in vacuum service, as specified in §§ 63.11910(c)(4), 63.11930(c) or 63.11930(h), you must submit to the Administrator the following information:

(i) The source, nature and cause of the discharge.

(ii) The date, time and duration of the discharge.

(iii) An estimate of the quantity of vinyl chloride and total HAP emitted during the discharge and the method used for determining this quantity.

(iv) The actions taken to prevent this discharge.

(v) The measures adopted to prevent future such discharges

(11) Affirmative defense report. If you seek to assert an affirmative defense, as provided in § 63.11895, then you must submit a written report as specified in § 63.11895(b) to demonstrate, with all necessary supporting documentation, that you have met the requirements set forth in § 63.11895(a).

(12) Overlap with Title V reports. Information required by this subpart, which is submitted with a Title V periodic report, does not need to be included in a subsequent compliance report required by this subpart or subpart referenced by this subpart. The Title V report must be referenced in the compliance report required by this subpart.

(c) *Other notifications and reports.* You must submit the other notification and reports, as specified in paragraphs (c)(1) through (9) of this section, as applicable.

(1) Notification of inspection. To provide the Administrator the opportunity to have an observer present, you must notify the Administrator at least 30 days before an inspection required by § 63.11910(a)(3). If an inspection is unplanned and you could not have known about the inspection 30 days in advance, then you must notify the Administrator at least 7 days before the inspection. Notification must be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, the notification including the written documentation may be made in writing and sent so that it is received by the Administrator at least 7 days before the inspection. If a delegated state or local agency is notified, you are not required to notify the Administrator. A delegated state or local agency may waive the requirement for notification of inspections.

(2) Batch precompliance report. You must submit a batch precompliance report at least 6 months prior to the compliance date of this subpart that includes a description of the test conditions, data, calculations and other information used to establish operating limits according to § 63.11935(d) for all batch operations. If you use an engineering assessment as specified in § 63.11950(i), then you must also include data or other information supporting a finding that the emissions estimation equations in § 63.11950(a) through (h) are inappropriate. If the EPA disapproves the report, then you must still be in compliance with the emission limitations and work practice standards of this subpart by your compliance date. To change any of the information submitted in the report, you must notify the EPA 60 days before you implement the planned change.

(3) Other control device reporting provisions. If you are using a control device other than those listed in this subpart, then you must submit the information as specified in paragraphs (c)(3)(i) through (iii) of this section.

(i) A description of the proposed control device.

(ii) A description of the parameter(s) to be monitored to ensure the control device is operated in conformance with its design and achieves the performance level as specified in this subpart and an explanation of the criteria used to select the parameter(s).

(iii) The frequency and content of monitoring, recording, and reporting if monitoring and recording is not continuous, or if the compliance report information, as specified in paragraph (b)(4)(i)(A) of this section, will not contain 3-hour block average values when the monitored parameter value does not meet the established operating limit. The rationale for the proposed monitoring, recording and reporting system must be included.

(4) Request for approval to use alternative monitoring methods. Prior to your initial notification of compliance status, you may submit requests for approval to use alternatives to the

continuous operating parameter monitoring specified in this rule, as provided for in § 63.11940(h), following the same procedure as specified in § 63.8. The information specified in paragraphs (c)(4)(i) and (ii) of this section must be included.

(i) A description of the proposed alternative system.

(ii) Information justifying your request for an alternative method, such as the technical or economic infeasibility, or the impracticality, of the affected source using the required method.

(5) Request for approval to monitor alternative parameters. Prior to your initial notification of compliance status, you may submit requests for approval to monitor a different parameter than those established in § 63.11935(d), following the same procedure as specified for alternative monitoring methods in § 63.8. The information specified in paragraphs (c)(5)(i) through (iii) of this section must be included in the request.

(i) A description of the parameter(s) to be monitored to ensure the control technology or pollution prevention measure is operated in conformance with its design and achieves the specified emission limit and an explanation of the criteria used to select the parameter(s).

(ii) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device, the schedule for this demonstration, and a statement that you will establish an operating limit for the monitored parameter(s) as part of the notification of compliance status if required under this subpart, unless this information has already been submitted.

(iii) The frequency and content of monitoring, recording, and reporting, if monitoring and recording is not continuous. The rationale for the proposed monitoring, recording, and reporting system must be included.

(6) [Reserved]

(7) Pressure relief device deviation report. If any pressure relief device in HAP service has discharged to the atmosphere as specified in § 63.11915(c), then you must submit to the Administrator within 10 days of the discharge the following information:

(i) The source, nature, and cause of the discharge.

(ii) The date, time, and duration of the discharge.

(iii) An estimate of the quantity of vinyl chloride and total HAP emitted during the discharge and the method used for determining this quantity.

(iv) The actions taken to prevent this discharge.

(v) The measures adopted to prevent future such discharges.

(8) Commencing and ceasing operation of continuous emissions monitoring systems. Before starting or stopping the use of CEMS you must notify the Administrator as specified in § 63.11935(b)(7).

(9) *Data submittal.* (i) Within 60 days after the date of completing each performance test (see § 63.2) required by this subpart, you must submit the results of performance tests electronically to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html*). Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(ii) Within 60 days after the date of completing each CEMS performance evaluation test (see § 63.2), you must submit the relative accuracy test audit data electronically into the EPA's CDX by using the ERT, as mentioned in paragraph (c)(9)(i) of this section. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically to the EPA's CDX.

(iii) All reports required by this subpart not subject to the requirements in paragraphs (c)(9)(i) and (ii) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.*, by electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraphs (c)(9)(i) and (ii) of this section in paper format.

§ 63.11990 What records must I keep?

You must keep records as specified in paragraphs (a) through (j) of this section, as applicable.

(a) *Copies of reports.* You must keep a copy of each notification and report that you submit to comply with this subpart, including all documentation supporting any notification or report. You must also keep copies of the current versions of the site-specific performance evaluation test plan, site-specific monitoring plan, and the equipment leak detection and repair plan.

(b) *Storage vessels.* For storage vessels, you must maintain the records specified in paragraphs (b)(1) through (6) of this section.

(1) You must keep a record of the dimensions of the storage vessel, an analysis of the capacity of the storage vessel and an identification of the liquid stored.

(2) Inspection records for fixed roofs complying with § 63.11910 including the information specified in paragraphs (b)(2)(i) and (ii) of this section.

(i) Record the date of each inspection required by § 63.11910(a)(3).

(ii) For each defect detected during an inspection required by § 63.11910(a)(3), record the location of the defect, a description of the defect, the date of detection and corrective action taken to repair the defect. In the event that repair of the defect is delayed in accordance with § 63.11910(a)(4)(ii), also record the reason for the delay and the date that completion of repair of the defect is expected.

(3) [Reserved]

(4) For pressure vessels, you must keep the records specified in paragraph (c) of this section for each pressure vessel.

(5) For internal and external floating roof storage vessels, you must maintain the records required in § 63.1065 of subpart WW of this part.

(6) For fixed roof storage vessels that route emissions through a closed vent system to a control device, during periods of planned routine maintenance of a control device, record the day and time at which planned routine maintenance periods begin and end, and the type of maintenance performed on the control device. If you need more than 240 hr/yr, keep a record that explains why additional time up to 360

hr/yr was needed and describes how you minimized the amount of additional time needed.

(c) *Equipment leaks.* For equipment leaks, you must maintain the records specified in § 63.1038 of subpart UU of this part for equipment leaks and a record of the information specified in § 63.11930(g)(4) for monitoring instrument calibrations conducted according to § 63.11930(e)(2).

(d) *Heat exchange systems.* For a heat exchange system subject to this subpart, you must keep the records specified in paragraphs (d)(1) through (6) of this section.

(1) Identification of all heat exchangers at the facility and the measured or estimated average annual HAP concentration of process fluid or intervening cooling fluid processed in each heat exchanger.

(2) Identification of all heat exchange systems that are in HAP service. For each heat exchange system that is subject to this subpart, you must include identification of all heat exchangers within each heat exchange system, identification of the individual heat exchangers in HAP service within each heat exchange system, and for closed-loop recirculation systems, the cooling tower included in each heat exchange system.

(3) Identification of all heat exchange systems that are exempt from the monitoring requirements according to the provisions in § 63.11920(b) and the provision under which the heat exchange system is exempt.

(4) Results of the following monitoring data for each monitoring event:

(i) Date/time of event.

(ii) Heat exchange exit line flow or cooling tower return line flow at the sampling location, gallons/minute.

(iii) Monitoring method employed.

(iv) The measured cooling water concentration for each of target analyte (parts per billion by weight).

(v) Calibration and recovery information identified in the test method used.

(5) The date when a leak was identified and the date when the heat exchanger was repaired or taken out of service.

(6) If a repair is delayed, the reason for the delay, the schedule for completing the repair, and the estimate of potential emissions for the delay of repair.

(e) *Process vent monitoring.* You must include the records specified in paragraphs (e)(1) through (4) of this section, as applicable, for process vent monitoring.

(1) Continuous records. Where this subpart requires a continuous record using CEMS or CPMS, you must maintain, at a minimum, the records specified in § 63.10(b)(2)(vii)(A).

(2) Excluded data. In any average computed to determine compliance, you must exclude monitoring data recorded during periods specified in paragraphs (e)(2)(i) through (iii) of this section.

(i) Periods of non-operation of the process unit (or portion thereof), resulting in cessation of the emissions to which the monitoring applies.

(ii) Periods of no flow to a control device.

(iii) Monitoring system malfunctions, repairs associated with monitoring system malfunctions or required monitoring system quality assurance or control activities, as specified in § 63.11890(c)(2).

(3) Records of calculated emission and operating parameter values. You must retain for 5 years, a record of CEMS and CPMS data as specified in paragraphs (e)(3)(i) and (ii) of this section, unless an alternative recordkeeping system has been requested and approved.

(i) Except as specified in paragraph (e)(3)(ii) of this section, retain for 5 years, the records of the average values for each continuously monitored operating parameter and pollutant specified in §§ 63.11925(e)(3)(ii) and 63.11925(e)(4)(ii)(B) for CEMS and CPMS.

(ii) In lieu of calculating and recording the average value specified in paragraphs (e)(3)(i) of this section, if all 1-hour averages specified in § 63.11935(e) demonstrate compliance with your parameter operating limit or the applicable pollutant emission limit in Table 1 or 2 to this subpart for the block average period, you may record a statement that all recorded 1-hour averages met the operating limit or emission limit, as applicable, and retain for 5 years this statement and all recorded CPMS or CEMS data for the block average period.

(4) Information to be included in records. You must keep records of each operating scenario as specified in paragraphs (e)(4)(i) through (viii) of this section, as applicable.

(i) You must keep a schedule or log of operating scenarios, updated each time a different operating scenario is put into effect.

(ii) A description of the process and the type of process components used.

(iii) An identification of related process vents including their associated emissions episodes.

(iv) The applicable control requirements of this subpart for process vents.

(v) The control device, including a description of operating and testing conditions.

(vi) Combined emissions that are routed to the same control device.

(vii) The applicable monitoring requirements of this subpart and any operating limit that assures compliance for all emissions routed to the control device.

(viii) Calculations and engineering analyses required to demonstrate compliance.

(f) *Process vents.* You must include the records specified in paragraphs (f)(1) and (2) of this section, as applicable, for process vents.

(1) Records of performance tests as required in § 63.10(b)(2)(viii). You must also collect the applicable control device operating parameters required in § 63.11940 over the full period of the performance test.

(2) If you use a control device to comply with this subpart and you are required to use CPMS, then you must keep up-to-date and readily accessible records for your process vents as specified in paragraphs (f)(2)(i) through (iv) of this section, as applicable.

(i) If you use a flow indicator, then you must keep records of periods of no flow to the control device, including the start and stop time and dates of periods of flow and no flow.

(ii) If you use a catalytic oxidizer for which you have selected the alternative monitoring specified in § 63.11940(b)(3), then you must also maintain records of the results of the annual catalyst sampling and inspections required by § 63.11940(b)(3)(i) and (ii) including any subsequent corrective actions taken.

(iii) If you use a regenerative adsorber as specified in § 63.11940(d), then the records specified in paragraphs (f)(2)(iii)(A) through (H) of this section, as applicable, must be kept.

(A) Records of total regeneration stream mass flow for each adsorber-bed regeneration cycle.

(B) Records of the temperature of the adsorber bed after each regeneration and within 15 minutes of completing any cooling cycle.

(C) For non-vacuum and non-steam regeneration systems, records of the temperature of the adsorber bed during each regeneration except during any temperature regulating (cooling or warming to bring bed temperature closer to vent gas temperature) portion of the regeneration cycle.

(D) If adsorber regeneration vacuum is monitored pursuant to § 63.11940(d)(4), then you must keep records of the

vacuum profile over time and the amount of time the vacuum level is below the minimum vacuum target for each adsorber-bed regeneration cycle.

(E) Records of the regeneration frequency and duration.

(F) Daily records of the verification inspections, including the visual observations and/or any activation of an automated alarm or shutdown system with a written entry into a log book or other permanent form of record.

(G) Records of the maximum volatile organic compound or HAP outlet concentration observed over the last 5 minutes of the adsorption cycle for each adsorber bed. Records must be weekly or for every regeneration cycle if the regeneration cycle is greater than 1 week.

(H) Records of the date and time the adsorbent had last been replaced.

(iv) If you use a non-regenerative adsorber as specified in § 63.11940(e), then the records specified in paragraphs (f)(2)(iv)(A) through (C) of this section, as applicable, must be kept.

(A) A record of the average life of the bed, as determined by § 63.11940(e)(1), including the date the average life was determined.

(B) Daily, weekly, or monthly records of the maximum volatile organic compound or HAP outlet concentration, as specified by § 63.11940(e)(2).

(C) Records of bed replacement including the date and time the adsorbent had last been replaced, and the date and time in which breakthrough is detected.

(g) *Closed vent systems.* You must keep the records specified in paragraphs (g)(1) through (6) of this section, and you must record any additional information as specified in § 63.11930, as applicable.

(1) Each alarm triggered because flow was detected in a bypass as specified in § 63.11930(g)(1)(i).

(2) Inspections of seals or closure mechanisms as specified in § 63.11930(g)(1)(ii).

(3) Copies of compliance reports for closed vent system leak inspections as specified in § 63.11985(b)(9) and § 63.11930(g)(2) and (3).

(4) Instrument calibration records as specified in § 63.11930(g)(4).

(5) Unsafe-to-inspect equipment as specified in § 63.11930(g)(5).

(6) Pressure alarms as specified by § 63.11930(h)(2) and (3).

(h) *Resin strippers.* For resin strippers, you must maintain the records specified in paragraphs (h)(1) and (2) of this section.

(1) All resin sampling data, including daily measurements of the concentration of vinyl chloride and monthly measurements of the total non-vinyl chloride organic HAP compounds in the stripped resin for each type and grade of resin produced. Each sample must be identified by the resin type and resin grade, the date and time the sample was taken, identification of the resin stripper from which the sample was taken, and the corresponding quantity (pounds) of resin processed by the stripper for the batch or over the time period represented by the sample.

(2) The total quantity (pounds) of each resin grade produced per day and the total quantity of resin processed by each resin stripper, identified by resin type and resin grade, per day.

(i) *Process wastewater.* For treatment processes, you must maintain the records specified in paragraphs (i)(1) through (5) of this section.

(1) A description of the process wastewater generation activities and treatment process.

(2) Records of the treatment determinations specified in § 63.11965(b) for each wastewater stream and the type of treatment applied if required in § 63.11965(c).

(3) Records of the initial performance test specified in § 63.11970(a) and (b).

(4) All testing data, including monthly measurements of the concentrations of vinyl chloride and the concentration of total non-vinyl chloride organic HAP in each process wastewater stream required to be measured, as specified in § 63.11975.

(5) You must keep any other applicable records that are required by the recordkeeping requirements specified in § 63.147 of subpart G of this part.

(j) *Other emission sources.* You must keep the records specified in paragraphs (j)(1) and (2) of this section.

(1) All engineering calculations, testing, sampling, and monitoring results and data specified in § 63.11955.

(2) Each occurrence that you do not comply with the requirements in § 63.11955.

§ 63.11995 In what form and how long must I keep my records?

(a) You must keep records for 5 years in a form suitable and readily available for expeditious review, as specified in § 63.10(b)(1).

(b) You must keep each record on site for at least 2 years, as specified in § 63.10(b)(1). You can keep the records off site for the remaining 3 years. Records may be maintained in hard copy or computer-readable format including, but not limited to, on paper, microfilm, hard disk drive, floppy disk, compact disk, magnetic tape or microfiche.

§ 63.12000 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the Administrator, as defined in § 63.2, or a delegated authority such as your state, local or tribal agency. If the Administrator has delegated authority to your state, local or tribal agency, then that agency (as well as the Administrator) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local or tribal agency, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the Administrator and are not transferred to the state, local or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission limits, operating limits, and work practice standards specified in this subpart.

(2) Approval of a major change to test methods, as defined in § 63.90, approval of any proposed analysis methods, and approval of any proposed test methods.

(3) Approval of a major change to monitoring, as defined in § 63.90.

(4) Approval of a major change to recordkeeping and reporting, as defined in § 63.90.

Definitions

§ 63.12005 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2, and in this section, as follows:

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

Batch emission episode means a discrete venting episode that is associated with a single unit operation. A unit operation may have more than one batch emission episode. For example, a displacement of vapor resulting from the charging of a vessel with HAP will result in a discrete emission episode that will last through the duration of the charge and will have an average flowrate equal to the rate of the charge. If the vessel is then heated, there will also be another discrete emission episode resulting from the expulsion of expanded vapor. Both

emission episodes may occur in the same vessel or unit operation. There are possibly other emission episodes that may occur from the vessel or other process components, depending on process operations.

Batch operation means a noncontinuous operation involving intermittent or discontinuous feed into process components, and, in general, involves the emptying of the process components after the operation ceases and prior to beginning a new operation. Addition of raw material and withdrawal of product do not occur simultaneously in a batch operation.

Batch process vent means a vent from a batch operation from a PVCPU through which a HAP-containing gas stream has the potential to be released to the atmosphere except that it is required by this subpart to routed to a closed vent system and control device. Emissions for all emission episodes associated with the unit operation(s) are part of the batch process vent. Batch process vents also include vents with intermittent flow from continuous operations. Examples of batch process vents include, but are not limited to, vents on condensers used for product recovery, polymerization reactors, and process tanks.

Bottoms receiver means a tank that collects bottoms from continuous distillation before the stream is sent for storage or for further downstream processing. A rundown tank is an example of a bottoms receiver.

Bulk process means a process for producing polyvinyl chloride resin that is characterized by a two-step anhydrous polymerization process: the formation of small resin particles in a pre-polymerization reactor using small amounts of vinyl chloride monomer, an initiator, and agitation; and the growth of the resin particles in a post-polymerization reactor using additional vinyl chloride monomer. Resins produced using the bulk process are referred to as bulk resins.

Bypass means diverting a process vent or closed vent system stream to the atmosphere such that it does not first pass through an emission control device.

Calendar year means the period between January 1 and December 31, inclusive for a given year.

Capacity means the nominal figure or rating given by the manufacturer of the storage vessel, condenser, or other process component.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Closed vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that collect or transport gas or vapor from an emission point to a control device.

Combustion device means an individual unit used for the combustion of organic emissions, such as a flare, incinerator, process heater, or boiler.

Conservation vent means an automatically operated (*e.g.*, weight-loaded or spring-loaded) safety device used to prevent the operating pressure of a storage vessel from exceeding the maximum allowable working pressure of the process component. Conservation vents must be designed to open only when the operating pressure of the storage vessel exceeds the maximum allowable working pressure of the process component. Conservation vents open and close to permit only the intake or outlet relief necessary to keep the storage vessel within permissible working pressures, and reseal automatically.

Container means a portable unit in which a material can be stored, transported, treated, disposed of or otherwise handled. Examples of containers include, but are not limited to, drums, pails, and portable cargo containers known as "portable tanks" or "totes." Container does not include transport vehicles or barges.

Continuous emission monitoring system (CEMS) means the total equipment that may be required to meet the data acquisition and availability requirements of this subpart, used to sample, condition (if applicable), analyze, and provide a record of emissions.

Continuous operation means any operation that is not a batch operation.

Continuous parameter monitoring system (CPMS) means the total equipment that may be required to meet the data acquisition and availability requirements of this part, used to sample, condition (if applicable), analyze, and provide a record of process or control system parameters.

Continuous process vent means a vent from a continuous PVCPU operation through which a HAP-containing gas stream has the potential to be released to the atmosphere except that it is required by this subpart to routed to a closed vent system and control device and has the following characteristics:

(1) The gas stream originates as a continuous flow from any continuous PVCPU operation during operation of the PVCPU.

(2) The discharge into the closed vent system and control device meets at least one of the following conditions:

(i) Is directly from any continuous operation.

(ii) Is from any continuous operation after passing solely (*i.e.*, without passing through any other unit operation for a process purpose) through one or more recovery devices within the PVCPU.

(iii) Is from a device recovering only mechanical energy from a gas stream that comes either directly from any continuous operation, or from any continuous operation after passing solely (*i.e.*, without passing through any other unit operation for a process purpose) through one or more recovery devices within the PVCPU.

Continuous PVCPU operation means any operation that is not a batch operation or an operation that generates a miscellaneous process vent.

Continuous record means documentation, either in hard copy or computer readable form, of data values measured at least once every 15 minutes and recorded at the frequency specified in § 63.11990(e)(1).

Control device means, with the exceptions noted in this definition, a combustion device, recovery device, recapture device or any combination of these devices used to comply with this subpart. Process condensers are not control devices.

Control system means the combination of the closed vent system and the control devices used to collect and control vapors or gases from a regulated emission source.

Cooling tower means a heat removal device used to remove the heat absorbed in circulating cooling water systems by transferring the heat to the atmosphere using natural or mechanical draft.

Cooling tower return line means the main water trunk lines at the inlet to the cooling tower before exposure to the atmosphere.

Corrective action plan means a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected corrective action is the best alternative, including, but not limited to, any consideration of cost-effectiveness.

Day means a calendar day, unless otherwise specified in this subpart.

Dioxin/furans means total tetra- through octachlorinated dibenzo-p-dioxins and dibenzofurans.

Dispersion process means a process for producing polyvinyl chloride resin that is characterized by the formation of the polymers in soap micelles that contain small amounts of vinyl chloride monomer. Emulsifiers are used to

disperse vinyl chloride monomer in the water phase. Initiators used in the dispersion process are soluble in water. Resins produced using the dispersion process are referred to as latex or dispersion resins.

Empty or emptying means the partial or complete removal of stored liquid from a storage vessel. Storage vessels that contain liquid only as a result of the liquid clinging to the walls or bottoms, or resting in pools due to bottom irregularities, are considered completely empty.

Equipment means each pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, connector and instrumentation system in HAP service; and any control devices or systems used to comply with this subpart.

Fill or filling means the introduction of liquid into a storage vessel, but not necessarily to capacity.

First attempt at repair, for the purposes of this subpart, means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere, followed by monitoring as specified in § 63.11930(f) to verify whether the leak is repaired, unless the owner or operator determines by other means that the leak is not repaired.

Fixed roof storage vessel means a vessel with roof that is mounted (*i.e.,* permanently affixed) on a storage vessel and that does not move with fluctuations in stored liquid level.

Flow indicator means a device that indicates whether gas flow is, or whether the valve position would allow gas flow to be, present in a line.

Gasholder means a surge control vessel with a bell that is floating in a vessel filled with water that is used to store gases from the PVC production process prior to being recovered or sent to a process vent control device. The bell rises and falls as low-pressure gases enter and leave the space beneath the bell and the water provides a seal between the enclosed gas within the floating bell and the ambient air.

Grade means the subdivision of PVC resin that describes it as a unique resin, *i.e.,* the most exact description of a type of resin with no further subdivision. Examples include low molecular weight suspension resins and general purpose suspension resins.

Hard-piping means pipes or tubing that are manufactured and properly installed using good engineering judgment and an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, American National Standards Institute (ANSI, 1819 L Street NW., 6th floor, Washington, DC 20036, (202) 293–8020, *http://www.ansi.org*).

Heat exchange system means a device or collection of devices used to transfer heat from process fluids to water without intentional direct contact of the process fluid with the water (*i.e.,* non-contact heat exchanger) and to transport and/or cool the water in a closed-loop recirculation system (cooling tower system) or a once-through system (*e.g.,* river or pond water). For closed-loop recirculation systems, the heat exchange system consists of a cooling tower, all heat exchangers that are serviced by that cooling tower and all water lines to and from the heat exchanger(s). For once-through systems, the heat exchange system consists of one or more heat exchangers servicing an individual process unit and all water lines to and from the heat exchanger(s). Intentional direct contact with process fluids results in the formation of a wastewater.

Heat exchanger exit line means the cooling water line from the exit of one or more heat exchangers (where cooling water leaves the heat exchangers) to either the entrance of the cooling tower return line or prior to exposure to the atmosphere or mixing with non-cooling water streams, in, as an example, a once-through cooling system, whichever occurs first.

In HAP service means that a process component either contains or contacts a liquid that is at least 5-percent HAP by weight or a gas that is at least 5 percent by volume HAP as determined according to the provisions of § 63.180(d). For the purposes of this definition, the term "organic HAP" as used in § 63.180(d) means HAP. The provisions of § 63.180(d) also specify how to determine that a process component is not in HAP service.

In vacuum service means that the process component is operating at an internal pressure that is at least 5 kilopascals (kPa) (0.7 pounds per square inch absolute) below ambient pressure.

Incinerator means an enclosed combustion device with an enclosed fire box that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. Any energy recovery section present is not physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section is a separate section following the combustion section and the two are joined by ducts or connections carrying flue gas. This energy recovery section limitation does not apply to an energy recovery section used solely to preheat the incoming vent stream or combustion air.

Maintenance wastewater means wastewater generated by the draining of process fluid from components in the PVCPU into an individual drain system prior to or during maintenance activities. Maintenance wastewater can be generated during planned and unplanned shutdowns and during periods not associated with a shutdown. Examples of activities that can generate maintenance wastewaters include descaling of heat exchanger tubing bundles, hydroblasting PVCPU process components such as polymerization reactors, vessels and heat exchangers, draining of low legs and high point bleeds, draining of pumps into an individual drain system, draining of portions of the PVCPU for repair and water used to wash out process components or equipment after the process components or equipment has already been opened to the atmosphere and has met the requirements of § 63.11955.

Maximum representative operating conditions means process operating conditions that result in the most challenging condition for the control device. The most challenging condition for the control device may include, but is not limited to, the highest or lowest HAP mass loading rate to the control device, the highest or lowest HAP mass loading rate of constituents that approach the limits of solubility for scrubbing media, the highest or lowest HAP mass loading rate of constituents that approach limits of solubility for scrubbing media.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the total HAP in the stored or transferred liquid at the temperature equal to the highest calendar-month average of the liquid storage or transfer temperature for liquids stored or transferred above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for liquids stored or transferred at the ambient temperature, as determined by any one of the following methods or references:

(1) In accordance with methods described in API MPMS 19.2 (incorporated by reference, see § 63.14).

(2) As obtained from standard reference texts.

(3) As determined by ASTM D2879–83 or ASTM D2879–96 (incorporated by reference, see § 63.14).

(4) Any other method approved by the Administrator.

Miscellaneous vent means gaseous emissions from samples, loading and unloading lines, slip gauges, process wastewater treatment systems and pressure relief devices that are routed through a closed vent system to a control device and that are not equipment leaks.

Nonstandard batch means a batch process that is operated outside of the range of operating conditions that are documented in an existing operating scenario, but is still a reasonably anticipated event. For example, a nonstandard batch occurs when additional processing or processing at different operating conditions must be conducted to produce a product that is normally produced under the conditions described by the standard batch. A nonstandard batch may be necessary as a result of a malfunction, but it is not itself a malfunction.

Operating block means a period of time that is equal to the time from the beginning to end of batch process operations within a process.

Operating day means a 24-hour period between 12 midnight and the following midnight during which PVC is produced at any time in the PVCPU. It is not necessary for PVC to be produced for the entire 24-hour period.

Operating scenario means, for the purposes of reporting and recordkeeping, any specific operation of a regulated process as described by reports specified in § 63.11985(b)(4)(ii) and records specified in § 63.11990(e)(4).

Plant site means all contiguous or adjoining property that is under common control, including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased or operated by the same entity, parent entity, subsidiary or any combination thereof.

Polymerization reactor means any vessel in which vinyl chloride is partially or totally polymerized into polyvinyl chloride. For bulk processes, the polymerization reactor includes pre-polymerization reactors and post-polymerization reactors.

Polyvinyl chloride means either polyvinyl chloride homopolymer or polyvinyl chloride copolymer.

Polyvinyl chloride and copolymers production process unit or PVCPU means a collection of process components assembled and connected by hard-piping or duct work, used to process raw materials and to manufacture polyvinyl chloride and/or polyvinyl chloride copolymers. A PVCPU includes, but is not limited to, polymerization reactors; resin stripping operations; resin blend tanks; resin centrifuges; resin dryers; resin product separators; recovery devices; reactant and raw material charge vessels and tanks, holding tanks, mixing and weighing tanks; finished resin product storage tanks or storage silos; finished resin product loading operations; connected ducts and piping; equipment including pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves and connectors and instrumentation systems. A PVCPU does not include chemical manufacturing process units, as defined in § 63.101, that produce vinyl chloride monomer or other raw materials used in the PVC polymerization process.

Polyvinyl chloride copolymer means a synthetic thermoplastic polymer that is derived from the simultaneous polymerization of vinyl chloride and another monomer such as vinyl acetate. Polyvinyl chloride copolymer is produced by different processes, including, but not limited to, suspension, dispersion/emulsion, suspension blending, and solution processes.

Polyvinyl chloride homopolymer means a synthetic thermoplastic polymer that is derived from the polymerization of vinyl chloride and has the general chemical structure (-H2CCHCl-)n. Polyvinyl chloride homopolymer is typically a white powder or colorless granule. Polyvinyl chloride homopolymer is produced by different processes, including (but not limited to), suspension, dispersion/emulsion, blending, and bulk processes.

Pressure relief device means a safety device used to prevent operating pressures from exceeding the maximum allowable working pressure of the process component. A common pressure relief device is a spring-loaded pressure relief valve.

Pressure vessel means a vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process change means an addition to or change in a PVCPU and/or its associated process components that creates one or more emission points or changes the characteristics of an emission point such that a new or different emission limit, operating parameter limit, or work practice requirement applies to the added or changed emission points. Examples of process changes include, but are not limited to, changes in production capacity, production rate, or catalyst type, or whenever there is replacement, removal, or addition of recovery device components. For purposes of this definition, process changes do not include process upsets, changes that do not alter the process component configuration and operating conditions, and unintentional, temporary process changes. A process change does not include moving within a range of conditions identified in the standard batch, and a nonstandard batch does not constitute a process change.

Process component means any unit operation or group of units operations or any part of a process or group of parts of a process that are assembled to perform a specific function (*e.g.*, polymerization reactor, dryers, etc.). Process components include equipment, as defined in this section.

Process condenser means a condenser whose primary purpose is to recover material as an integral part of a batch process. All condensers recovering condensate from a batch process at or above the boiling point or all condensers in line prior to a vacuum source are considered process condensers. Typically, a primary condenser or condensers in series are considered to be integral to the batch regulated process if they are capable of and normally used for the purpose of recovering chemicals for fuel value (*i.e.*, net positive heating value), use, reuse or for sale for fuel value, use or reuse. This definition does not apply to a condenser that is used to remove materials that would hinder performance of a downstream recovery device as follows:

(1) To remove water vapor that would cause icing in a downstream condenser.

(2) To remove water vapor that would negatively affect the adsorption capacity of carbon in a downstream carbon adsorber.

(3) To remove high molecular weight organic compounds or other organic compounds that would be difficult to remove during regeneration of a downstream adsorber.

Process tank means a tank or other vessel (*e.g.*, pressure vessel) that is used within an affected source to both: (1) Collect material discharged from a feedstock storage vessel, process tank, or other PVCPU process component, and (2) discharge the material to another process tank, process component, byproduct storage vessel, or product storage vessel.

Process unit means the process components assembled and connected by pipes or ducts to process raw and/or intermediate materials and to manufacture an intended product. For the purpose of this subpart, process unit

includes, but is not limited to, polyvinyl chloride production process.

Process vent means a vent stream that is the result of the manifolding of each and all batch process vent, continuous process vent, or miscellaneous vent resulting from the affected facility into a closed vent system and into a common header that is routed to a control device. The process vent standards apply at the outlet of the control device. A process vent is either a PVC-only process vent or a PVC-combined process vent.

Process wastewater means wastewater that comes into direct contact with HAP or results from the production or use of any raw material, intermediate product, finished product, by-product, or waste product containing HAP, but that has not been discharged untreated as wastewater. Examples are product tank drawdown or feed tank drawdown; water formed during a chemical reaction or used as a reactant; water used to wash impurities from organic products or reactants; water used to cool or quench organic vapor streams through direct contact; water discarded from a control device; and condensed steam from jet ejector systems pulling vacuum on vessels containing organics. Gasholder seal water is not process wastewater until it is removed from the gasholder.

Process wastewater treatment system means a specific technique or collection of techniques that remove or destroy the organics in a process wastewater stream to comply with §§ 63.11965, 63.11970, and 63.11975.

Product means a polymer produced using the same monomers and varying in additives (*e.g.*, initiators, terminators, etc.); catalysts; or in the relative proportions of monomers, that is manufactured by a process unit. With respect to polymers, more than one recipe may be used to produce the same product, and there can be more than one grade of a product. Product also means a chemical that is not a polymer, which is manufactured by a process unit. By-products, isolated intermediates, impurities, wastes, and trace contaminants are not considered products.

PVC-combined process vent means a process vent that originates from a PVCPU and is combined with one or more process vents originating from another source category prior to being controlled or emitted to the atmosphere.

PVC-only process vent means a process vent that originates from a PVCPU and is not combined with a process vent originating from another source category prior to being controlled or emitted to the atmosphere.

Recipe means a specific composition from among the range of possible compositions that may occur within a product, as defined in this section. A recipe is determined by the proportions of monomers and, if present, other reactants and additives that are used to make the recipe.

Recovery device means an individual process component capable of and normally used for the purpose of recovering chemicals for fuel value (*i.e.*, net positive heating value), use, reuse, or for sale for fuel value, use, or reuse. Examples of process components that may be recovery devices include absorbers, adsorbers, condensers, oil-water separators or organic-water separators, or organic removal devices such as decanters, strippers (*e.g.*, wastewater steam and vacuum strippers), or thin-film evaporation units. For purposes of this subpart, recovery devices are control devices.

Repaired, for the purposes of this subpart, means equipment that is adjusted or otherwise altered to eliminate a leak as defined in the applicable sections of this subpart; and unless otherwise specified in applicable provisions of this subpart, is inspected as specified in § 63.11930(f) to verify that emissions from the equipment are below the applicable leak definition.

Resin stripper means a unit that removes organic compounds from a raw polyvinyl chloride and copolymer product. In the production of a polymer, stripping is a discrete step that occurs after the polymerization reaction and before drying or other finishing operations. Examples of types of stripping include steam stripping, vacuum stripping, or other methods of devolatilization. For the purposes of this subpart, devolatilization that occurs in dryers or other finishing operations is not resin stripping. Resin stripping may occur in a polymerization reactor or in a batch or continuous stripper separate from the polymerization reactor where resin stripping occurs.

Root cause analysis means an assessment conducted through a process of investigation to determine the primary cause, and any other significant contributing cause(s), of a discharge of gases in excess of specified thresholds.

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.

Slip gauge means a gauge that has a probe that moves through the gas/liquid interface in a storage vessel and indicates the level of product in the vessel by the physical state of the material the gauge discharges.

Solution process means a process for producing polyvinyl chloride copolymer resin that is characterized by the anhydrous formation of the polymer through precipitation. Polymerization occurs in an organic solvent in the presence of an initiator where vinyl chloride monomer and co-monomers are soluble in the solvent, but the polymer is not. The PVC copolymer is a granule suspended in the solvent, which then precipitates out of solution. Emulsifiers and suspending agents are not used in the solution process. PVC copolymer resins produced using the solution process are referred to as solution resins.

Specific gravity monitoring device means a unit of equipment used to monitor specific gravity and having a minimum accuracy of ±0.02 specific gravity units.

Standard procedure means a formal written procedure officially adopted by the plant owner or operator and available on a routine basis to those persons responsible for carrying out the procedure.

Storage vessel means a tank or other vessel (*e.g.*, pressure vessel) that is part of an affected source and is used to store a gaseous, liquid, or solid feedstock, byproduct, or product that contains organic HAP. Storage vessel does not include:

(1) Vessels permanently attached to motor vehicles such as trucks, railcars, barges, or ships;

(2) Process tanks;

(3) Vessels with capacities smaller than 10,040 gallons;

(4) Vessels storing organic liquids that contain organic HAP only as impurities;

(5) Bottoms receiver tanks;

(6) Surge control vessels; and

(7) Wastewater storage tanks. Wastewater storage tanks are covered under the wastewater provisions.

Stripped resin means the material exiting the resin stripper that contains polymerized vinyl chloride.

Supplemental combustion air means the air that is added to a vent stream after the vent stream leaves the unit operation. Air that is part of the vent stream as a result of the nature of the unit operation is not considered supplemental combustion air. Air required to operate combustion device burner(s) is not considered supplemental combustion air. Air required to ensure the proper operation of catalytic oxidizers, to include the intermittent addition of air upstream of the catalyst bed to maintain a minimum threshold flow rate through the catalyst bed or to avoid excessive temperatures in the catalyst bed, is not considered to be supplemental combustion air.

Surge control vessel means feed drums, recycle drums, and intermediate vessels used as a part of any continuous operation. Surge control vessels are used within an affected source when in-process storage, mixing, or management of flow rates or volumes is needed to introduce material into continuous operations. Surge control vessels also include gasholders.

Suspension blending process means a process for producing polyvinyl chloride resin that is similar to the suspension polymerization process, but employs a rate of agitation that is significantly higher than the highest range for non-blending suspension resins. The suspension blending process uses a recipe that creates extremely small resin particles, generally equal to or less than 100 microns in size, with a glassy surface and very little porosity. The suspension blending process concentrates the resins using a centrifuge that is specifically designed to handle these small particles. Polyvinyl chloride resins produced using the suspension blending process are referred to as suspension blending resins and are typically blended with dispersion resins.

Suspension process means a process for producing polyvinyl chloride resin that is characterized by the formation of the polymers in droplets of liquid vinyl chloride monomer or other co-monomers suspended in water. The droplets are formed by agitation and the use of protective colloids or suspending agents. Initiators used in the suspension process are soluble in vinyl chloride monomer. Polyvinyl chloride resins produced using the suspension process are referred to as suspension resins.

Table 10 HAP means a HAP compound listed in table 10 of this subpart.

Total non-vinyl chloride organic HAP means, for the purposes of this subpart, the sum of the measured concentrations of each HAP, as calculated according to the procedures specified in §§ 63.11960(f) and 63.11980(b).

Type of resin means the broad classification of PVC homopolymer and copolymer resin referring to the basic manufacturing process for producing that resin, including, but not limited to, suspension, dispersion/emulsion, suspension blending, bulk, and solution processes.

Unloading operations means the transfer of organic liquids from a transport vehicle, container, or storage vessel to process components within the affected source.

Wastewater means process wastewater and maintenance wastewater. The following are not considered wastewater for the purposes of this subpart:

(1) Stormwater from segregated sewers;

(2) Water from fire-fighting and deluge systems, including testing of such systems;

(3) Spills;

(4) Water from safety showers;

(5) Samples of a size not greater than reasonably necessary for the method of analysis that is used;

(6) Equipment leaks;

(7) Wastewater drips from procedures such as disconnecting hoses after cleaning lines; and

(8) Noncontact cooling water.

Wastewater stream means a stream that contains only wastewater as defined in this section.

Work practice standard means any design, equipment, work practice or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

TABLE 1 TO SUBPART HHHHHHH OF PART 63—EMISSION LIMITS AND STANDARDS FOR EXISTING AFFECTED SOURCES

For this type of emission point . . .	And for this air pollutant . . .	And for an affected source producing this type of PVC resin . . .	You must meet this emission limit . . .
1. PVC-only process vents [a]	a. Vinyl chloride	All resin types	6.0 parts per million by volume (ppmv).
	b. Total hydrocarbons	All resin types	9.7 ppmv measured as propane.
	c. Total organic HAP [b]	All resin types	56 ppmv.
	d. Hydrogen chloride	All resin types	78 ppmv.
	e. Dioxins/furans (toxic equivalency basis).	All resin types	0.038 nanograms per dry standard cubic meter (ng/dscm).
2. PVC-combined process vents [a]	a. Vinyl chloride	All resin types	1.1 ppmv.
	b. Total hydrocarbons	All resin types	4.2 ppmv measured as propane.
	c. Total organic HAP [b]	All resin types	9.8 ppmv.
	d. Hydrogen chloride	All resin types	380 ppmv.
	e. Dioxins/furans (toxic equivalency basis).	All resin types	0.051 ng/dscm.
3. Stripped resin	a. Vinyl chloride	i. Bulk resin	7.1 parts per million by weight (ppmw).
		ii. Dispersion resin	1300 ppmw.
		iii. Suspension resin	37 ppmw.
		iv. Suspension blending resin	140 ppmw.
		v. Copolymer resin	790 ppmw.
	b. Total non-vinyl chloride organic HAP.	i. Bulk resin	170 ppmw.
		ii. Dispersion resin	240 ppmw.
		iii. Suspension resin	670 ppmw.
		iv. Suspension blending resin	500 ppmw.
		v. Copolymer resin	1900 ppmw.
4. Process Wastewater	a. Vinyl chloride	All resin types	6.8 ppmw.
	b. Total non-vinyl chloride organic HAP.	All resin types	110 ppmw.

[a] Emission limits at 3 percent oxygen, dry basis.
[b] Total organic HAP is alternative compliance limit for THC.

TABLE 2 TO SUBPART HHHHHHH OF PART 63—EMISSION LIMITS AND STANDARDS FOR NEW AFFECTED SOURCES

For this type of emission point . . .	And for this air pollutant . . .	And for an affected source producing this type of PVC resin . . .	You must meet this emission limit . . .
1. PVC-only process vents[a]	a. Vinyl chloride	All resin types	0.56 ppmv.
	b. Total hydrocarbons	All resin types	7.0 ppmv measured as propane.
	c. Total organic HAP[b]	All resin types	5.5 ppmv.
	d. Hydrogen chloride	All resin types	0.17 ppmv.
	e. Dioxins/furans (toxic equivalency basis).	All resin types	0.038 ng/dscm.
2. PVC-combined process vents[a]	a. Vinyl chloride	All resin types	0.56 ppmv.
	b. Total hydrocarbons	All resin types	2.3 ppmv measured as propane.
	c. Total organic HAP[b]	All resin types	5.5 ppmv.
	d. Hydrogen chloride	All resin types	1.4 ppmv.
	e. Dioxins/furans (toxic equivalency basis).	All resin types	0.034 nanograms per dry standard cubic meter (ng/dscm).
3. Stripped resin	a. Vinyl chloride	i. Bulk resin	7.1 parts per million by weight (ppmw).
		ii. Dispersion resin	480 ppmw.
		iii. Suspension resin	7.3 ppmw.
		iv. Suspension blending resin	140 ppmw.
		v. Copolymer—all resin types	790 ppmw.
	b. Total non-vinyl chloride organic HAP.	i. Bulk resin	170 ppmw.
		ii. Dispersion resin	66 ppmw.
		iii. Suspension resin	15 ppmw.
		iv. Suspension blending resin	500 ppmw.
		v. Copolymer resin	1900 ppmw.
4. Process Wastewater	a. Vinyl chloride	All resin types	0.28 ppmw.
	b. Total non-vinyl chloride organic HAP.	All resin types	0.018 ppmw.

[a] Emission limits at 3 percent oxygen, dry basis.
[b] Total organic HAP is alternative compliance limit for THC.

TABLE 3 TO SUBPART HHHHHHH OF PART 63—SUMMARY OF CONTROL REQUIREMENTS FOR STORAGE VESSELS AT NEW AND EXISTING SOURCES

If the storage vessel capacity (gallons) is . . .	And the vapor pressure[a] (psia) is . . .	Then, you must use the following type of storage vessel . . .
≥20,000 but <40,000	≥4	Internal floating roof, external floating roof, or fixed roof vented to a closed vent system and control device achieving 95 percent reduction.[b]
≥40,000	≥0.75	Internal floating roof, external floating roof, or fixed roof vented to a closed vent system and control device achieving 95 percent reduction.[b]
Any capacity.	>11.1	Pressure vessel.[c]
All other capacity and vapor pressure combinations		Fixed roof.[d]

[a] Maximum true vapor pressure of total HAP at storage temperature.
[b] If using a fixed roof storage vessel vented to a closed vent system and control device, you must meet the requirements in § 63.11910(a) for fixed roof storage vessels. If using an internal floating roof storage vessel or external floating roof storage vessels, you must meet the requirements in § 63.11910(b) for internal floating roof storage vessels or external floating roof storage vessels, as applicable.
[c] Meeting the requirements of § 63.11910(c) for pressure vessels.
[d] Meeting the requirements in § 63.11910(a) for fixed roof storage vessels.

TABLE 4 TO SUBPART HHHHHHH OF PART 63—APPLICABILITY OF THE GENERAL PROVISIONS TO PART 63

Citation	Subject	Applies to subpart HHHHHHH	Comment
§ 63.1(a)(1)–(a)(4), (a)(6), (a)(10)–(a)(12), (b)(1), (b)(3), (c)(1), (c)(2), (c)(5), (e).	Applicability	Yes.	
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3), (c)(4), (d).	[Reserved]	No.	
§ 63.2	Definitions	Yes	Additional definitions are found in § 63.12005.
§ 63.3	Units and abbreviations	Yes.	
§ 63.4(a)(1), (a)(2), (b), (c)	Prohibited activities and circumvention.	Yes.	
§ 63.4(a)(3)–(a)(5)	[Reserved]	No.	

TABLE 4 TO SUBPART HHHHHHH OF PART 63—APPLICABILITY OF THE GENERAL PROVISIONS TO PART 63—Continued

Citation	Subject	Applies to subpart HHHHHHH	Comment
§ 63.5(a), (b)(1), (b)(3), (b)(4), (b)(6), (d)–(f).	Preconstruction review and notification requirements.	Yes.	
§ 63.5(b)(2), (b)(5), (c)	[Reserved]	No.	
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c)(1), (c)(2), (c)(5), (e)(1)(iii), (f)(2), (f)(3), (g), (i), (j).	Compliance with standards and maintenance requirements.	Yes	§ 63.11875 specifies compliance dates.
§ 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(2)(ii), (h)(3), (h)(5)(iv).	[Reserved]	No	
§ 63.6(e)(1)(i), (e)(1)(ii), (e)(3), (f)(1).	Startup, shutdown, and malfunction provisions.	No. See § 63.11890(b) for general duty requirement.	
§ 63.6(h)(1), (h)(2)(i), (h)(2)(iii), (h)(4), (h)(5)(i)–(h)(5)(iii), (h)(5)(v), (h)(6)–(h)(9).	Compliance with opacity and visible emission standards.	No	Subpart HHHHHHH does not specify opacity or visible emission standards.
§ 63.7(a)(1), (a)(2), (a)(3), (a)(4), (b)–(d), (e)(2)–(e)(4), (f), (g)(1), (g)(3), (h).	Performance testing requirements	Yes.	
§ 63.7(a)(2)(i)–(viii)	[Reserved]	No.	
§ 63.7(a)(2)(ix)	Performance testing requirements	Yes.	
§ 63.7(e)(1)	Performance testing	No. See especially § 63.11945, 63.11960(d), 63.11980(a).	
§ 63.7(g)(2)	[Reserved]	No.	
§ 63.8(a)(1), (a)(2), (a)(4), (b), (c)(1)(i), (c)(1)(ii), (c)(2)–(c)(4), (c)(6)–(c)(8).	Monitoring requirements	Yes	Except cross reference in § 63.8(c)(1)(i) to § 63.6(e)(1) is replaced with a cross-reference to § 63.11890(b).
§ 63.8(a)(3)	[Reserved]	No.	
§ 63.8(c)(1)(iii)	Requirement to develop SSM plan for continuous monitoring systems.	No.	
§ 63.8(c)(5)	Continuous opacity monitoring system minimum procedures.	No	Subpart HHHHHHH does not have opacity or visible emission standards.
§ 63.8(d)	Written procedures for continuous monitoring systems.	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.	
§ 63.8(e)	Continuous monitoring systems performance evaluation.	Yes.	
§ 63.8(f)	Use of an alternative monitoring method.	Yes.	
§ 63.8(g)	Reduction of monitoring data	Yes	Except that the minimum data collection requirements are specified in § 63.11935(e).
§ 63.9(a), (b)(1), (b)(2), (b)(4)(i), (b)(4)(v), (b)(5), (c)–(e), (g)(1), (g)(3), (h)(1)–(h)(3), (h)(5), (h)(6), (i), (j).	Notification requirements	Yes.	
§ 63.9(f)	Notification of opacity and visible emission observations.	No	Subpart HHHHHHH does not have opacity or visible emission standards.
§ 63.9(g)(2)	Use of continuous opacity monitoring system data.	No	Subpart HHHHHHH does not require the use of continuous opacity monitoring system.
§ 63.9(b)(3), (b)(4)(ii)–(iv), (h)(4)	[Reserved]	No.	
§ 63.10(a), (b)(1)	Recordkeeping and reporting requirements.	Yes.	
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.	
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See §§ 63.11895(b), 63.11985(b)(4)(i), 63.11985(b)(9) through (11), and 63.11985(c)(7).	
§ 63.10(b)(2)(iii)	Maintenance records	Yes.	
§ 63.10(b)(2)(iv), (b)(2)(v)	Actions taken to minimize emissions during SSM.	No.	
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions.	Yes.	
§ 63.10(b)(2)(vii)–(x)	Other CMS requirements	Yes.	
§ 63.10(b)(2)(xi)–(xiv)	Other recordkeeping requirements	Yes.	
§ 63.10(b)(3)	Recordkeeping requirement for applicability determinations.	Yes.	

TABLE 4 TO SUBPART HHHHHHH OF PART 63—APPLICABILITY OF THE GENERAL PROVISIONS TO PART 63—Continued

Citation	Subject	Applies to subpart HHHHHHH	Comment
§ 63.10(c)(1), (c)(5), (c)(6)	Additional recordkeeping requirements for sources with continuous monitoring systems.	Yes.	
§ 63.10(c)(2)–(4), (c)(9)	[Reserved]	No.	
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions during SSM.	Yes.	
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.	
§ 63.10(c)(10)	Recording nature and cause of malfunctions.	No. See §§ 63.11895(b), 63.11985(b)(4)(i), 63.11985(b)(9) through (11), and 63.11985(c)(7).	
63.10(c)(11), (c)(12)	Recording corrective actions	No. See §§ 63.11895(b), 63.11985(b)(4)(i), 63.11985(b)(9) through (11), and 63.11985(c)(7).	
§ 63.10(c)(13)–(14)	Records of the total process operating time during the reporting period and procedures that are part of the continuous monitoring system quality control program.	Yes.	
§ 63.10(c)(15)	Use SSM plan	No.	
§ 63.10(d)(1)	General reporting requirements	Yes.	
§ 63.10(d)(2)	Performance test results	Yes.	
§ 63.10(d)(3)	Opacity or visible emissions observations.	No	Subpart HHHHHHH does not specify opacity or visible emission standards.
§ 63.10(d)(4)	Progress reports	Yes.	
§ 63.10(d)(5)	SSM reports	No. See §§ 63.11895(b), 63.11985(b)(4)(i), 63.11985(b)(9) through (11), and 63.11985(c)(7).	
§ 63.10(e)(1)	Additional continuous monitoring system reports—general.	Yes.	
§ 63.10(e)(2)(i)	Results of continuous monitoring system performance evaluations.	Yes.	
§ 63.10(e)(2)(ii)	Results of continuous opacity monitoring system performance evaluations.	No	Subpart HHHHHHH does not require the use of continuous opacity monitoring system.
§ 63.10(e)(3)	Excess emissions/continuous monitoring system performance reports.	Yes.	
§ 63.10(e)(4)	Continuous opacity monitoring system data reports.	No	Subpart HHHHHHH does not require the use of continuous opacity monitoring system.
§ 63.10(f)	Recordkeeping/reporting waiver	Yes.	
63.11(a)	Control device and work practice requirements—applicability.	Yes.	
§ 63.11(b)	Flares	No	Facilities subject to subpart HHHHHHH do not use flares as control devices, as specified in § 63.11925(b).
§ 63.11(c)–(e)	Alternative work practice for monitoring equipment for leaks.	Yes.	
§ 63.12	State authority and delegations	Yes	§ 63.12000 identifies types of approval authority that are not delegated.
§ 63.13	Addresses	Yes.	
§ 63.14	Incorporations by reference	Yes	Subpart HHHHHHH incorporates material by reference.
§ 63.15	Availability of information and confidentiality.	Yes.	
§ 63.16	Performance track provisions	Yes.	

TABLE 5 TO SUBPART HHHHHHH OF PART 63—OPERATING PARAMETERS, OPERATING LIMITS AND DATA MONITORING, RECORDING AND COMPLIANCE FREQUENCIES FOR PROCESS VENTS

For these control devices, you must monitor these operating parameters . . .	Establish the following operating limit during your initial performance test . . .	Monitor, record, and demonstrate continuous compliance using these minimum frequencies		
		Data measurement	Data recording	Data averaging period for compliance
Process Vents				
Any Control device				
Flow to/from the control device.	N/A	Continuous	N/A	Date and time of flow start and stop.
Thermal Oxidizers				
Temperature (in fire box or downstream ductwork prior to heat exchange).	Minimum temperature	Continuous	Every 15 minutes	3-hour block average.
Temperature differential across catalyst bed.	Minimum temperature differential.	Continuous	Every 15 minutes	3-hour block average.
Inlet temperature to catalyst bed and catalyst condition.	Minimum inlet temperature and catalyst condition as specified in 63.11940 (b)(3).	Continuous for temperature, annual for catalyst condition.	Every 15 minutes for temperature, annual for catalyst condition.	3-hour block average for temperature, annual for catalyst condition.
Absorbers and Acid Gas Scrubbers				
Influent liquid flow	Minimum inlet liquid flow	Continuous	Every 15 minutes	3-hour block average.
Influent liquid flow and gas stream flow.	Minimum influent liquid flow to gas stream flow ratio.	Continuous	Every 15 minutes	3-hour block average.
Pressure drop	Minimum pressure drop	Continuous	Every 15 minutes	3-hour block average.
Exhaust gas temperature	Maximum exhaust gas temperature.	Continuous	Every 15 minutes	3-hour block average.
Change in specific gravity of scrubber liquid.	Minimum change in specific gravity.	Continuous	Every 15 minutes	3-hour block average.
pH of effluent liquid	Minimum pH	Continuous	Every 15 minutes	3-hour block average.
Causticity of effluent liquid	Minimum causticity	Continuous	Every 15 minutes	3-hour block average.
Conductivity of effluent liquid.	Minimum conductivity	Continuous	Every 15 minutes	3-hour block average.
Regenerative Adsorber				
Regeneration stream flow.	Minimum total flow per regeneration cycle.	Continuous	N/A	Total flow for each regeneration cycle.
Adsorber bed temperature.	Maximum temperature	Continuously after regeneration and within 15 minutes of completing any temperature regulation.	Every 15 minutes after regeneration and within 15 minutes of completing any temperature regulation.	3-hour block average.
Adsorber bed temperature.	Minimum temperature	Continuously during regeneration except during any temperature regulating portion of the regeneration cycle.	N/A	Average of regeneration cycle.
Vacuum and duratio of regeneration.	Minimum vacuum and period of time for regeneration.	Continuous	N/A	Average vacuum and duration of regeneration.
Regeneration frequency	Minimum regeneration frequency and duration.	Continuous	N/A	Date and time of regeneration start and stop.
Adsorber operation valve sequencing and cycle time.	Correct valve sequencing and minimum cycle time.	Daily	Daily	N/A.
Non-Regenerative Adsorber				
Average adsorber bed life.	N/A	Daily until breakthrough for 3 adsorber bed changeouts.	N/A	N/A.

TABLE 5 TO SUBPART HHHHHHH OF PART 63—OPERATING PARAMETERS, OPERATING LIMITS AND DATA MONITORING, RECORDING AND COMPLIANCE FREQUENCIES FOR PROCESS VENTS—Continued

For these control devices, you must monitor these operating parameters . . .	Establish the following operating limit during your initial performance test . . .	Monitor, record, and demonstrate continuous compliance using these minimum frequencies		
		Data measurement	Data recording	Data averaging period for compliance
Outlet VOC concentration of the first adsorber bed in series.	Limits in Table 1 or 2 of this subpart.	Daily, except monthly (if more than 2 months bed life remaining) or weekly (if more than 2 weeks bed life remaining).	N/A	Daily, weekly, or monthly.
Condenser				
Temperature	Maximum outlet temperature.	Continuous	Every 15 minutes	3-hour block average.

TABLE 6 TO SUBPART HHHHHHH OF PART 63—TOXIC EQUIVALENCY FACTORS

Dioxin/furan congener	Toxic equivalency factor
2,3,7,8-tetrachlorodibenzo-p-dioxin	1
1,2,3,7,8-pentachlorodibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorodibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorodibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorodibenzo-p-dioxin	0.1
1,2,3,4,6,7,8-heptachlorodibenzo-p-dioxin	0.01
octachlorodibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorodibenzofuran	0.1
2,3,4,7,8-pentachlorodibenzofuran	0.3
1,2,3,7,8-pentachlorodibenzofuran	0.03
1,2,3,4,7,8-hexachlorodibenzofuran	0.1
1,2,3,6,7,8-hexachlorodibenzofuran	0.1
1,2,3,7,8,9-hexachlorodibenzofuran	0.1
2,3,4,6,7,8-hexachlorodibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorodibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorodibenzofuran	0.01
Octachlorodibenzofuran	0.0003

TABLE 7 TO SUBPART HHHHHHH OF PART 63—CALIBRATION AND ACCURACY REQUIREMENTS FOR CONTINUOUS PARAMETER MONITORING SYSTEMS

If you monitor this parameter . . .	Then your accuracy requirements are . . .	And your inspection/calibration frequency requirements are . . .
1. Temperature (non-cryogenic temperature ranges).	±1 percent of temperature measured or 2.8 degrees Celsius (5 degrees Fahrenheit) whichever is greater.	Every 12 months.
2. Temperature (cryogenic temperature ranges).	±2.5 percent of temperature measured or 2.8 degrees Celsius (5 degrees Fahrenheit) whichever is greater.	Every 12 months.
3. Liquid flow rate	±2 percent of the normal range of flow	a. Every 12 months. b. You must select a measurement location where swirling flow or abnormal velocity distributions due to upstream and downstream disturbances at the point of measurement do not exist.
4. Gas flow rate	±5 percent of the flow rate or 10 cubic feet per minute, whichever is greater.	a. Every 12 months. b. Check all mechanical connections for leakage at least annually. c. At least annually, conduct a visual inspection of all components of the flow CPMS for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow CPMS is not equipped with a redundant flow sensor.
5. pH or caustic strength	±0.2 pH units	Every 8 hours of process operation check the pH or caustic strength meter's calibration on at least two points.

TABLE 7 TO SUBPART HHHHHHH OF PART 63—CALIBRATION AND ACCURACY REQUIREMENTS FOR CONTINUOUS PARAMETER MONITORING SYSTEMS—Continued

If you monitor this parameter . . .	Then your accuracy requirements are . . .	And your inspection/calibration frequency requirements are . . .
6. Conductivity	±5 percent of normal range	Every 12 months.
7. Mass flow rate	±5 percent of normal range	Every 12 months.
8. Pressure	±5 percent or 0.12 kilopascals (0.5 inches of water column) whichever is greater.	a. Calibration is required every 12 months. b. Check all mechanical connections for leakage at least annually. c. At least annually perform a visual inspection of all components for integrity, oxidation and galvanic corrosion if CPMS is not equipped with a redundant pressure sensor.

TABLE 8 TO SUBPART HHHHHHH OF PART 63—METHODS AND PROCEDURES FOR CONDUCTING PERFORMANCE TESTS FOR PROCESS VENTS

For each control device used to meet the emission limit in Table 1 or 2 to this subpart for the following pollutant . . .	You must . . .	Using . . .
1. Total hydrocarbons	a. Measure the total hydrocarbon concentration at the outlet of the final control device or in the stack.	Method 25A at 40 CFR part 60, appendix A–7. Conduct each test run for a minimum of 1 hour.
2. Total organic HAP	a. Measure the total organic HAP concentration at the outlet of the final control device or in the stack.	i. Method 18 at 40 CFR part 60, appendix A–6 and ASTM D6420–99.[a] Conduct each test run for a minimum of 1 hour. ii. Method 320 at 40 CFR part 63, appendix A and ASTM D6348–03.[a] Conduct each test run for a minimum of 1 hour.
3. Vinyl chloride	a. Measure the vinyl chloride concentration at the outlet of the final control device or in the stack.	Method 18 at 40 CFR part 60, appendix A–6. Conduct each test run for a minimum of 1 hour.
4. Hydrogen chloride	a. Measure hydrogen chloride concentrations at the outlet of the final control device or in the stack.	i. Method 26 at 40 CFR part 60, appendix A–8, collect 60 dry standard liters of gas per test run; or ii. Method 26A at 40 CFR part 60, appendix A–8, collect 1 dry standard cubic meter of gas per test run.
5. Dioxin/furan	a. Measure dioxin/furan concentrations on a toxic equivalency basis (and report total mass per isomer) at the outlet of the final control device or in the stack.	Method 23 at 40 CFR part 60, appendix A–7 and collect 5 dry standard cubic meters of gas per test run.
6. Any pollutant from a continuous, batch, or combination of continuous and batch process vent(s).	a. Select sampling port locations and the number of traverse points.	Method 1 or 1A at 40 CFR part 60, appendix A–1.
	b. Determine gas velocity and volumetric flow rate.	Method 2, 2A, 2C, 2D, 2F, or 2G at 40 CFR part 60, appendix A–1 and A–2.
	c. Conduct gas molecular weight analysis and correct concentrations the specified percent oxygen in Table 1 or 2 to this subpart.	Method 3, 3A, or 3B at 40 CFR part 60, appendix A–2 using the same sampling site and time as HAP samples.
	d. Measure gas moisture content	Method 4 at 40 CFR part 60, appendix A–3.

[a] Incorporated by reference, see § 63.14.

TABLE 9 TO SUBPART HHHHHHH OF PART 63—PROCEDURES FOR CONDUCTING SAMPLING OF STRIPPED RESIN AND PROCESS WASTEWATER

For demonstrating . . .	For the following emission points and types of processes . . .	Collect samples according to the following schedule . . .	
		Vinyl chloride . . .	Total non-vinyl chloride organic HAP . . .
Each stripped resin stream			
1. Initial compliance	a. Continuous	Every 8 hours or for each grade, whichever is more frequent during a 24 hour period.	Every 8 hours or for each grade, whichever is more frequent during a 24 hour period.
	b. Batch	1 grab sample for each batch produced during a 24 hour period.	1 grab sample for each batch produced during a 24 hour period.

TABLE 9 TO SUBPART HHHHHHH OF PART 63—PROCEDURES FOR CONDUCTING SAMPLING OF STRIPPED RESIN AND PROCESS WASTEWATER—Continued

For demonstrating . . .	For the following emission points and types of processes . . .	Collect samples according to the following schedule . . .	
		Vinyl chloride . . .	Total non-vinyl chloride organic HAP . . .
2. Continuous compliance	a. Continuous	On a daily basis, 1 grab sample every 8 hours or for each grade, whichever is more frequent during a 24 hour period.	On a monthly basis, 1 grab sample every 8 hours or for each grade, whichever is more frequent during a 24 hour period.
	b. Batch	On a daily basis, 1 grab sample for each batch produced during a 24 hour period.	On a monthly basis, 1 grab sample for each batch produced during a 24 hour period.
Each process wastewater stream			
3. Initial compliance	N/A	1 grab sample	1 grab sample.
4. Continuous compliance	N/A	1 grab sample per month	1 grab sample per month.

TABLE 10 TO SUBPART HHHHHHH OF PART 63—HAP SUBJECT TO THE RESIN AND PROCESS WASTEWATER PROVISIONS AT NEW AND EXISTING SOURCES

CAS No.	HAP	Analyte category	Test method
107211	Ethylene glycol	Alcohol	SW–846–8015C.[a]
67561	Methanol	Alcohol	SW–846–8015C.[a]
75070	Acetaldehyde	Aldehyde	SW–846–8315A.[a]
50000	Formaldehyde	Aldehyde	SW–846–8315A.[a]
51285	2,4-dinitrophenol	SVOC	SW–846–8270D.[a]
98862	Acetophenone	SVOC	SW–846–8270D.[a]
117817	Bis(2-ethylhexyl) phthalate (DEHP)	SVOC	SW–846–8270D.[a]
123319	Hydroquinone	SVOC	SW–846–8270D.[a]
108952	Phenol	SVOC	SW–846–8270D.[a]
79345	1,1,2,2-tetrachloroethane	VOC	SW–846–8260B.[a]
106990	1,3-butadiene	VOC	SW–846–8260B.[a]
540841	2,2,4-trimethylpentane	VOC	SW–846–8260B.[a]
71432	Benzene	VOC	SW–846–8260B.[a]
108907	Chlorobenzene	VOC	SW–846–8260B.[a]
67663	Chloroform	VOC	SW–846–8260B.[a]
126998	Chloroprene	VOC	SW–846–8260B.[a]
98828	Cumene	VOC	SW–846–8260B.[a]
75003	Ethyl chloride (Chloroethane)	VOC	SW–846–8260B.[a]
100414	Ethylbenzene	VOC	SW–846–8260B.[a]
107062	Ethylene dichloride (1,2-Dichloroethane)	VOC	SW–846–8260B.[a]
75343	Ethylidene dichloride (1,1-Dichloroethane)	VOC	SW–846–8260B.[a]
74873	Methyl chloride (Chloromethane)	VOC	SW–846–8260B.[a]
75092	Methylene chloride	VOC	SW–846–8260B.[a]
110543	n-Hexane	VOC	SW–846–8260B.[a]
108883	Toluene	VOC	SW–846–8260B.[a]
71556/79005	Trichloroethane	VOC	SW–846–8260B.[a]
108054	Vinyl acetate	VOC	SW–846–8260B.[a]
593602	Vinyl bromide	VOC	SW–846–8260B.[a]
75014	Vinyl chloride	VOC	Method 107 at 40 CFR part 61, appendix B.
75354	Vinylidene chloride (1,1-Dichloroethylene)	VOC	SW–846–8260B.[a]
1330207	Xylenes (isomers and mixtures)	VOC	SW–846–8260B.[a]

[a] Incorporated by reference, see § 63.14.

[FR Doc. 2012–6421 Filed 4–16–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044, FRL–9611–4]

RIN 2060–AP52; RIN 2060–AR31

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On May 3, 2011, under authority of Clean Air Act (CAA) sections 111 and 112, the EPA proposed both national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs) and standards of performance for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial-institutional steam generating units (76 FR 24976). After consideration of public comments, the EPA is finalizing these rules in this action.

Pursuant to CAA section 111, the EPA is revising standards of performance in response to a voluntary remand of a final rule. Specifically, we are amending new source performance standards (NSPS) after analysis of the public comments we received. We are also finalizing several minor amendments, technical clarifications, and corrections to existing NSPS provisions for fossil fuel-fired EGUs and large and small industrial-commercial-institutional steam generating units.

Pursuant to CAA section 112, the EPA is establishing NESHAP that will require coal- and oil-fired EGUs to meet hazardous air pollutant (HAP) standards reflecting the application of the maximum achievable control technology. This rule protects air quality and promotes public health by reducing emissions of the HAP listed in CAA section 112(b)(1).

DATES: This final rule is effective on April 16, 2012. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of April 16, 2012.

ADDRESSES: The EPA established two dockets for this action: Docket ID. No. EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID No. EPA–HQ–OAR–2009–0234 (NESHAP action). All documents in the dockets are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility 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) 566–1741.

FOR FURTHER INFORMATION CONTACT: For the NESHAP action: Mr. William Maxwell, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5430; Fax number (919) 541–5450; Email address: *maxwell.bill@epa.gov*. For the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–4003; Fax number (919) 541–5450; Email address: *fellner.christian@epa.gov*.

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I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by the final standards are shown in Table 1 of this preamble.

TABLE 1—POTENTIALLY AFFECTED REGULATED CATEGORIES AND ENTITIES

Category	NAICS code [1]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by the federal government.
State/local/tribal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by states, tribes, or municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian country.

[1] North American Industry Classification System.
[2] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather is meant to provide a guide for readers regarding entities likely to be affected by this action. To determine whether you, as owner or operator of a facility, company, business, organization, etc., will be regulated by this action, you should examine the applicability criteria in 40 CFR 60.40, 60.40Da, or 60.40c or in 40 CFR 63.9981. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

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

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

C. Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 16, 2012. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment (including any public hearing) can be raised during judicial review. This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule[.]" Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

D. What are the costs and benefits of this final rule?

Consistent with Executive Order (EO) 13563, "Improving Regulation and Regulatory Review," we have estimated the costs and benefits of the final rule. This rule will reduce emissions of HAP, including mercury (Hg), from the electric power industry. Installing the technology necessary to reduce emissions directly regulated by this rule will also reduce the emissions of directly emitted $PM_{2.5}$ and sulfur dioxide (SO_2), a $PM_{2.5}$ precursor. The benefits associated with these PM and SO_2 reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA estimates that this final rule will yield annual monetized benefits (in 2007$) of between $37 to $90 billion using a 3 percent discount rate and $33 to $81 billion using a 7 percent discount rate. The great majority of the estimates are attributable to co-benefits from reductions in $PM_{2.5}$-related mortality. The annual social costs, approximated

by the sum of the compliance costs and monitoring and reporting costs, are $9.6 billion (2007$) and the annual quantified net benefits (the difference between benefits and costs) are $27 to $80 billion using a 3 percent discount rate or $24 to $71 billion using a 7 percent discount rate. It is important to note that the $PM_{2.5}$ co-benefits reported here contain uncertainty, due in part to the important assumption that all fine particles are equally potent in causing premature mortality and because many of the benefits are associated with reducing $PM_{2.5}$ levels at the low end of the concentration distributions examined in the epidemiology studies from which the $PM_{2.5}$-mortality relationships used in this analysis are derived.

The benefits of this rule outweigh costs by between 3 to 1 or 9 to 1 depending on the benefit estimate and discount rate used. The co-benefits are substantially attributable to the 4,200 to 11,000 fewer $PM_{2.5}$-related premature mortalities estimated to occur as a result of this rule. The EPA could not monetize some costs and important benefits, such as some Hg benefits and those for the HAP reduced by this final rule other than Hg. Upon considering these limitations and uncertainties, it remains clear that the benefits of this rule, referred to in short as the Mercury and Air Toxics Standards (MATS), are substantial and far outweigh the costs.

TABLE 2—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE FINAL RULE IN 2016

[Billions of 2007$] [a]

	3% Discount rate	7% Discount rate
Total Monetized Benefits [b]	$37 to $90	$33 to $81.
Partial Hg-related Benefits [c]	$0.004 to $0.006	$0.0005 to $0.001.
$PM_{2.5}$-related Co-benefits [b]	$36 to $89	$33 to $80.
Climate-related Co-Benefits [d]	$0.36	$0.36.
Total Social Costs [e]	$9.6	$9.6.
Net Benefits	$27 to $80	$24 to $71.
Non-monetized Benefits	Visibility in Class I areas. Other neurological effects of Hg exposure. Other health effects of Hg exposure. Health effects of ozone and direct exposure to SO_2 and NO_2. Ecosystem effects. Health effects from commercial and non-freshwater fish consumption. Health risks from exposure to non-mercury HAP.	

[a] All estimates are for 2016, and are rounded to two significant figures.

[b] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits. Benefits in this table are nationwide and are associated with directly emitted $PM_{2.5}$ and SO_2 reductions. The estimate of social benefits also includes CO_2-related benefits calculated using the social cost of carbon, discussed further in chapter 5 of the RIA. Mercury benefits were calculated using the baseline from proposal. The difference in emissions reductions between proposal and final does not substantially affect the Hg benefits.

[c] Based on an analysis of health effects due to recreational freshwater fish consumption.

[d] This table shows monetized CO_2 co-benefits that were calculated using the global average social cost of carbon estimate at a 3 percent discount rate. In section 5.6 of the Regulatory Impact Analysis (RIA) we also report the monetized CO_2 co-benefits using discount rates of 5 percent, 2.5 percent, and 3 percent (95th percentile).

[e] Total social costs are approximated by the compliance costs for both coal- and oil-fired units. This includes monitoring, recordkeeping, and reporting costs.

For more information on how EPA is addressing EO 13563, see the EO discussion in the Statutory and Executive Order Reviews section of this preamble.

II. Background Information on the NESHAP

On May 3, 2011, the EPA proposed this rule to address emissions of toxic air pollutants from coal and oil-fired electric generating units as required by the CAA. The proposal explained at length the statutory history and requirements leading to this rule, the factual and legal basis for the rule and its specific provisions, and the costs and benefits to the public health and environment from the proposed requirements.

The EPA received over 900,000 comments from members of the public on the proposed rule, substantially more than for any other prior regulatory proposal. The comments express concerns about the presence of Hg in the environment and the effect it has on human health, concerns about the costs of the rule, how challenging it may be for some sources to comply and questions about the impact it may have on this country's electricity supply and economy. Many comments provided additional information and data that have enriched the factual record and enabled EPA to finalize a rule that fulfills the mandate of the CAA while providing flexibility and compliance options to affected sources—options that make the rule less costly and compliance more readily manageable.

This rule establishes uniform emissions-control standards that sources can meet with proven and available technologies and operational processes in a timeframe that is achievable. They will put this industry, now the single largest source of Hg emissions in the United States (U.S.) with emissions of 29 tons per year, on a path to reducing those emissions by approximately 90 percent. Emissions of other toxic metals, such as arsenic (As) and nickel (Ni), dioxins and furans, acid gases (including hydrochloric acid (HCl) and SO_2) will also decrease dramatically with the installation of pollution controls. And the flexibilities established in this rule along with other available tools provide a clear pathway to compliance without jeopardizing the country's energy supply.

This preamble explains EPA's appropriate and necessary finding, the elements of the final rule, key changes the EPA is making in response to comments submitted on the proposed rule, and our responses to many of the comments we received. A full response to comments is provided in the response to comments document available in the docket for this rulemaking.

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

Congress established a specific structure for determining whether to regulate EGUs under CAA section 112.[1] Specifically, Congress enacted CAA section 112(n)(1).

Section 112(n)(1)(A) of the CAA requires the EPA to conduct a study to evaluate the remaining public health hazards that are reasonably anticipated to occur as a result of EGUs' HAP emissions after imposition of CAA requirements. The EPA must report the results of that study to Congress, and regulate EGUs "if the Administrator finds such regulation is appropriate and necessary," after considering the results of that study. Thus, CAA section 112(n)(1)(A) governs how the Administrator decides whether to list EGUs for regulation under CAA section 112. *See New Jersey* v. *EPA*, 517 F.3d 574 at 582 (D.C. Cir. 2008) ("Section 112(n)(1) governs how the Administrator decides whether to list EGUs; it says nothing about delisting EGUs.").

As directed, the EPA conducted the study to evaluate the remaining public health hazards and reported the results to Congress (Utility Study Report to Congress (Utility Study)).[2] We discuss this study below in conjunction with other studies that CAA section 112(n)(1) requires concerning EGUs. See also 76 FR 24982–24984 (summarizing studies).

Once the EPA lists a source category pursuant to CAA section 112(c), the EPA must then establish technology-based emission standards under CAA section 112(d). For major sources, the EPA must establish emission standards that "require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section" that the EPA determines are achievable taking into account certain statutory factors. *See* CAA section 112(d)(2). These standards are referred to as "maximum achievable control technology" or "MACT" standards. The MACT standards for existing sources must be at least as stringent as the average emission limitation achieved by the best performing 12 percent of existing sources in the category (for which the Administrator has emissions information) or the best performing 5 sources for source categories with less than 30 sources. *See* CAA section 112(d)(3)(A) and (B), respectively. This level of minimum stringency is referred to as the "MACT floor," and the EPA cannot consider cost in setting the floor. For new sources, MACT standards must be at least as stringent as the control level achieved in practice by the best controlled similar source. *See* CAA section 112(d)(3).

The EPA also must consider more stringent "beyond-the-floor" control options. When considering beyond-the-floor options, the EPA must consider the maximum degree of reduction in HAP emissions and take into account costs, energy, and non-air quality health and environmental impacts when doing so. *See Cement Kiln Recycling Coal.* v. *EPA*, 255 F.3d 855, 857–58 (D.C. Cir. 2001).

Alternatively, the EPA may set a health-based standard for HAP that have an established health threshold, and the standard must provide "an ample margin of safety." *See* CAA section 112(d)(4). As these standards could be less stringent than MACT standards, the Agency must have detailed information on HAP emissions from the subject sources and sources located near the subject sources before exercising its discretion to set such standards.

For area sources, the EPA may issue standards or requirements that provide for the use of generally available control technologies or management practices (GACT standards) in lieu of promulgating MACT or health-based standards. *See* CAA section 112(d)(5).

As noted above, CAA section 112(n) requires completion of various reports concerning EGUs. For the first report, the Utility Study, Congress required the EPA to evaluate the hazards to public health reasonably anticipated to occur as the result of HAP emissions from EGUs after imposition of the requirements of the CAA. *See* CAA section 112(n)(1)(A). The EPA was required to report results from this study to Congress by November 15, 1993. *Id.* Congress also directed the EPA to conduct "a study of mercury emissions from [EGUs], municipal waste combustion units, and other sources, including area sources" (Mercury Study). *See* CAA section 112(n)(1)(B). The EPA was required to report the results from this study to Congress by November 15, 1994. *Id.* In conducting this Mercury Study, Congress directed the EPA to "consider the rate and mass of such emissions, the health and environmental effects of such emissions, technologies which are available to control such emissions, and the costs of such technologies." *Id.* Congress directed the National Institute of Environmental Health Sciences (NIEHS) to conduct the last required evaluation, "a study to determine the threshold level of mercury exposure below which adverse human health effects are not expected to occur" (NIEHS Study). *See* CAA section 112(n)(1)(C). The NIEHS was required to submit the results to Congress by November 15, 1993. *Id.* In conducting this study, NIEHS was to determine "a threshold for mercury concentrations in the tissue of fish which may be consumed (including consumption by sensitive populations) without adverse effects to public health." *Id.*

In addition, Congress, in conference report language associated with the EPA's fiscal year 1999 appropriations, directed the EPA to fund the National Academy of Sciences (NAS) to perform an independent evaluation of the available data related to the health impacts of methylmercury (MeHg) (NAS Study or MeHg Study). H.R. Conf. Rep. No 105–769, at 281–282 (1998). Specifically, Congress required NAS to advise the EPA as to the appropriate reference dose (RfD) for MeHg. 65 FR 79826. The RfD is the amount of a chemical which, when ingested daily over a lifetime, is anticipated to be without adverse health effects to humans, including sensitive subpopulations. In the same conference report, Congress indicated that the EPA should not make the appropriate and necessary regulatory determination for Hg emissions until the EPA had reviewed the results of the NAS Study. *See* H.R. Conf. Rep. No 105–769, at 281–282 (1998).

As directed by Congress through different vehicles, the NAS Study and the NIEHS Study evaluated the same issues. The NIEHS completed the NIEHS Study in 1995,[3] and the NAS completed the NAS Study in 2000.[4] Because NAS completed its study 5 years after the NIEHS Study, and considered additional information not earlier available to NIEHS, for purposes of this document we discuss the content of the NAS Study as opposed to the NIEHS Study.

The EPA conducted the studies required by CAA section 112(n)(1) concerning utility HAP emissions, the Utility Study and the Mercury Study,[5] and completed both by 1998. Prior to issuance of the Mercury Study, the EPA

[1] "Electric utility steam generating unit" is defined, in part, as any "fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale." *See* CAA section 112(a)(8).

[2] U.S. EPA. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress. EPA–453/R–98–004a. February 1998.

[3] NIEHS Study, August 1995; EPA–HQ–OAR–2009–3053.

[4] National Research Council (NAS). 2000. Toxicological Effects of Methylmercury. Committee on the Toxicological Effects of Methylmercury, Board on Environmental Studies and Toxicology, National Research Council.

[5] Mercury Study Report to Congress, December 1997; EPA–HQ–OAR–2009–0234–3054.

engaged in two extensive external peer reviews of the document.

On December 20, 2000, the EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under CAA section 112(d). In making that finding, the EPA considered the Utility Study, the Mercury Study, the NAS Study, and certain additional information, including information about Hg emissions from coal-fired EGUs that the EPA obtained pursuant to an information collection request (ICR) under the authority of CAA section 114. 65 FR 79826–27.

B. What is the litigation history of this final rule?

Shortly after issuance of the December 2000 finding, an industry group challenged that finding in the Court of Appeals for the D.C. Circuit (D.C. Circuit). *Utility Air Regulatory Group (UARG)* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001). The D.C. Circuit dismissed the lawsuit holding that it did not have jurisdiction because CAA section 112(e)(4) provides, in pertinent part, that "no action of the Administrator * * * listing a source category or subcategory under subsection (c) of this section *shall be a final agency action subject to judicial review*, except that any such action may be reviewed under section 7607 of (the CAA) when the Administrator issues emission standards for such pollutant or category." *Id. (emphasis added).*

Pursuant to a settlement agreement, the deadline for issuing emission standards was March 15, 2005. However, instead of issuing emission standards pursuant to CAA section 112(d), on March 29, 2005, the EPA issued the Section 112(n) Revision Rule (2005 Action). That action delisted EGUs after finding that it was neither appropriate nor necessary to regulate such units under CAA section 112. In addition, on May 18, 2005, the EPA issued the Clean Air Mercury Rule (CAMR). 70 FR 28606. That rule established standards of performance for emissions of Hg from new and existing coal-fired EGUs pursuant to CAA section 111.

Environmental groups, states, and tribes challenged the 2005 Action and CAMR. Among other things, the environmental and state petitioners argued that the EPA could not remove EGUs from the CAA section 112(c) source category list without following the requirements of CAA section 112(c)(9).

On February 8, 2008, the D.C. Circuit vacated both the 2005 Action and CAMR. The D.C. Circuit held that the EPA failed to comply with the requirements of CAA section 112(c)(9) for delisting source categories. Specifically, the D.C. Circuit held that CAA section 112(c)(9) applies to the removal of "any source category" from the CAA section 112(c) list, including EGUs. The D.C. Circuit found that, by enacting CAA section 112(c)(9), Congress limited the EPA's discretion to reverse itself and remove source categories from the CAA section 112(c) list. The D.C. Circuit found that the EPA's contrary position would "nullify § 112(c)(9) altogether." *New Jersey* v. *EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008). The D.C. Circuit did not reach the merits of petitioners' arguments on CAMR, but vacated CAMR for existing sources because coal-fired EGUs were already listed sources under CAA section 112. The D.C. Circuit reasoned that even under the EPA's own interpretation of the CAA, regulation of existing sources' Hg emissions under CAA section 111 was prohibited if those sources were a listed source category under CAA section 112.[6] *Id.* The D.C. Circuit vacated and remanded CAMR for new sources because it concluded that the assumptions the EPA made when issuing CAMR for new sources were no longer accurate (*i.e.*, that there would be no CAA section 112 regulation of EGUs and that the CAA section 111 standards would be accompanied by standards for existing sources). *Id.* at 583–84. Thus, CAMR and the 2005 Action became null and void.

On December 18, 2008, several environmental and public health organizations filed a complaint in the U.S. District Court for the District of Columbia.[7] They alleged that the Agency had failed to perform a nondiscretionary duty under CAA section 304(a)(2), by failing to promulgate final CAA section 112(d) standards for HAP from coal- and oil-fired EGUs by the statutorily-mandated deadline, December 20, 2002, 2 years after such sources were listed under CAA section 112(c). The EPA settled that litigation. The consent decree resolving the case requires the EPA to sign a notice of proposed rulemaking setting forth the EPA's proposed CAA section 112(d) emission standards for coal- and oil-fired EGUs by March 16, 2011, and a notice of final rulemaking by December 16, 2011.[8]

C. What is the relationship between this final rule and other combustion rules?

1. CAA Section 111

The EPA promulgated revised NSPS for SO_2, nitrogen oxides (NO_X), and PM under CAA section 111 for EGUs (40 CFR part 60, subpart Da) and industrial boilers (IB) (40 CFR part 60, subparts Db and Dc) on February 27, 2006 (71 FR 9866). As noted elsewhere, in this action we are finalizing certain amendments to 40 CFR part 60, subpart Da. In developing this final rule, we considered the monitoring, testing, and recordkeeping requirements of the existing and revised NSPS to avoid duplicating requirements to the extent possible.

2. CAA Section 112

The EPA has previously developed other non-EGU combustion-related NESHAP under CAA section 112(d). The EPA promulgated final NESHAP for major source industrial, commercial and institutional boilers and process heaters (IB) and area source industrial, commercial and institutional boilers on March 21, 2011 (40 CFR part 63, subpart DDDDD, 76 FR 15608; and subpart JJJJJJ, 76 FR 15249, respectively), and promulgated standards for stationary combustion turbines (CT) on March 5, 2004 (40 CFR part 63 subpart YYYY; 69 FR 10512). In addition to these three NESHAP, on March 21, 2011, the EPA also promulgated final CAA section 129 standards for commercial and institutional solid waste incineration (CISWI) units, including energy recovery units (40 CFR part 60, subparts CCCC (NSPS) and DDDD (emission guidelines); 76 FR 15704); and a definition of non-hazardous secondary materials that are solid waste (Non-hazardous Solid Waste Definition Rule (40 CFR part 241, subpart B; 76 FR 15456)). Electric generating units and IB

[6] In CAMR and the 2005 Action, EPA interpreted section 111(d) of the Act as prohibiting the Agency from establishing an existing source standard of performance under CAA section 111(d) for any HAP emitted from a particular source category, if the source category is regulated under CAA section 112.

[7] American Nurses Association, Chesapeake Bay Foundation, Inc., Conservation Law Foundation, Environment America, Environmental Defense Fund, Izaak Walton League of America, Natural Resources Council of Maine, Natural Resources Defense Council, Physicians for Social Responsibility, Sierra Club, The Ohio Environmental Council, and Waterkeeper Alliance, Inc. (Civ. No. 1:08–cv–02198 (RMC)).

[8] The consent decree originally required EPA to sign a notice of final rulemaking no later than November 16, 2011; however, on October 21, 2011, pursuant to paragraph 6 of the consent decree, the parties agreed to a 30-day extension of the final rule deadline. As stated in the stipulation memorializing the extension, the parties agreed to the extension of 30 days because EPA provided an additional 30 days for public comment and the time was necessary to respond to comments submitted on the proposed rule.

that combust fossil fuel and solid waste, as that term is defined by the Administrator pursuant to the Resource Conservation and Recovery Act (RCRA), *see* 76 FR 15456, will be subject to standards issued pursuant to CAA section 129 (*e.g.*, CISWI), unless they meet one of the exemptions in CAA section 129(g)(1). Clean Air Act section 129 standards are discussed in more detail below.

The two IB (Boiler) NESHAP, the CT NESHAP, and this final rule will regulate HAP emissions from sources that combust fossil fuels for electrical power, process operations, or heating. The differences among these rules are due to the size of the units (megawatt (MW), megawatt-electric (MWe), or British thermal unit per hour (Btu/hr)), the boiler/furnace technology, and/or the portion of their electrical output (if any) for sale to any utility power distribution systems.

Pursuant to the CAA, an EGU is "any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit." CAA section 112(a)(8). We consider all of the MW ratings quoted in the final rule to be the original rated nameplate capacity of the unit. We consider cogeneration to be the simultaneous production of power (electricity) and another form of useful thermal energy (usually steam or hot water) from a single fuel-consuming process.

We consider any combustion unit, regardless of size, that produces steam to serve a generator that produces electricity exclusively for industrial, commercial, or institutional purposes (*i.e.*, makes no sales to the national electrical distribution grid) to be an IB unit. We do not consider a fossil fuel-fired combustion unit that serves a generator that produces electricity for sale to be an EGU under the final rule if the size of the combustion unit is less than or equal to 25 MW. Units that are 25 MW or less are likely subject to one of the two Boiler NESHAP.

Because of the combustion technology of simple-cycle and combined-cycle stationary CTs (with the exception of integrated gasification combined cycle (IGCC) units that burn gasified coal or petroleum coke synthesis gas/syngas), we do not consider these CTs to be EGUs for purposes of this final rule.[9]

The December 2000 listing discussed above did not list natural gas-fired EGUs. Thus, this final rule does not regulate a unit that otherwise meets the CAA section 112(a)(8) definition of an EGU but that combusts natural gas exclusively or natural gas in combination with another fossil fuel where the natural gas constitutes 90.0 percent or more of the average annual heat input during any 3 consecutive calendar years or 85.0 percent or more of the annual heat input in one calendar year. We consider such units to be natural gas-fired EGUs notwithstanding the combustion of some coal or oil (or derivative thereof) and such units are not subject to this final rule.

The CAA does not define the terms "fossil fuel-fired" and "fossil fuel." In this rule, we are finalizing definitions for both terms for purposes of this rule. The definition of "fossil fuel-fired" will help determine the applicability of the final rule to combustion units that sell electricity to the utility power distribution system. The definition of "fossil fuel-fired" establishes the amount of fossil fuel combustion necessary to make a unit "fossil fuel-fired" and hence potentially subject to this final rule. These definitions will help determine applicability of the final rule to units that primarily fire non-fossil fuels (*e.g.*, biomass) but generally start up using either natural gas or distillate oil and may use these fuels (or coal) during normal operation for flame stabilization.

In addition, the EPA is finalizing in the definition of "fossil fuel-fired" that, among other things, an EGU must fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date in order to be considered a fossil fuel-fired EGU subject to this final rule. The EPA has based these threshold percentage values on the definition of "oil-fired" in the Acid Rain Program (ARP) found at 40 CFR 72.2. Though the EPA does not have annual heat input data for, for example, biomass co-fired EGUs because their use is not yet commonplace, we believe this definition accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this final rule.

[9] The CT NESHAP regulates HAP emissions from all simple-cycle and combined-cycle stationary CTs producing electricity or steam for any purpose.

Units that do not meet the EGU definition will in most cases be considered IB units subject to one of the two Boiler NESHAP. Thus, for example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.*, less than or equal to 10.0 percent of the average annual heat input in any 3 consecutive calendar years or less than or equal to 15.0 percent of the annual heat input during any one calendar year) is not considered to be a fossil fuel-fired EGU under this final rule.

A cogeneration facility that sells electricity to any utility power distribution system equal to more than one-third of its potential electric output capacity and more than 25 MW will be considered an EGU if the facility is fossil fuel-fired as that term is defined in the final rule.

We recognize that different CAA section 112 rules may impact a particular unit at different times. For example, the Boiler NESHAP may cover some cogeneration units. Such a unit may decide to increase or decrease the proportion of production output it supplies to the electric utility grid, thus causing the unit to meet the EGU cogeneration criteria (*i.e.*, greater than one-third of its potential output capacity and greater than 25 MW). A unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the final EGU NESHAP.

Another rule intersection may occur where one or more coal- or oil-fired EGU(s) share an air pollution control device (APCD) and/or an exhaust stack with one or more similarly-fueled IB unit(s). To demonstrate compliance with two different rules, either the emissions would need to be apportioned to the appropriate source or the more stringent emission limit would need to be met. Data needed to apportion emissions are not currently required by this final rule or the final boiler NESHAP and are not otherwise available. Therefore, the EPA is finalizing the requirement to comply with the more stringent emission limit.

3. CAA Section 129

Clean Air Act section 129 regulates units that combust "non-hazardous secondary materials," as that term is defined by the Administrator under the Resource Conservation and Recovery Act (RCRA), that are "solid wastes." On March 21, 2011, the EPA promulgated the final Non-Hazardous Solid Waste Definition Rule (76 FR 15456). Any EGU that combusts any solid waste as defined in that final rule is a solid waste

incineration unit subject to emissions standards under CAA section 129.

In the Non-Hazardous Solid Waste Definition Rule, the EPA determined that coal refuse from current mining operations is not considered to be a "solid waste" if it is not discarded. Coal refuse that is in legacy coal refuse piles is considered a "solid waste" because it has been discarded. However, if discarded coal refuse is processed in the same manner as currently mined coal refuse, the coal refuse would not be considered a solid waste but instead would be considered a product fossil fuel. Therefore, the combustion of such material by a combustion unit would not subject that unit to regulation under CAA section 129. Instead, the unit would be subject to this final rule if it meets the definition of EGU. In the proposed rule, we assumed that all units that combust coal refuse and otherwise meet the definition of a coal-fired EGU are in fact combusting newly mined coal refuse or coal refuse from legacy piles that has been processed such that it is not a solid waste. We did not receive any information since proposal that would cause us to revise this determination in the final rule.

Further, CAA section 129(g)(1)(B) exempts from regulation

"* * * qualifying small power production facilities, as defined in section 796(17)(C) of Title 16, or qualifying cogeneration facilities, as defined in section 796(18)(B) of Title 16, which burn homogeneous waste * * * for the production of electric energy or in the case of qualifying cogeneration facilities which burn homogeneous waste for the production of electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes * * *"

If the "homogeneous waste" material that such facilities combust is also a fossil fuel, and those facilities otherwise meet the definition of an EGU under CAA section 112(a)(8), then those facilities are exempt from regulation under CAA section 129 but covered under this final rule. For example, a qualifying small power production facility or cogeneration facility combusting only coal refuse that is a solid waste and a "homogenous waste," as that term is defined in the final CAA section 129 CISWI standards, would be subject to this final rule if the unit also met the definition of EGU.

D. What are the health effects of pollutants emitted from coal- and oil-fired EGUs?

This final rule protects air quality and promotes public health by reducing emissions of some of the HAP listed in CAA section 112(b)(1). Utilities are by far the largest anthropogenic source of Hg in the U.S. In addition, EGUs are the largest source of HCl, hydrogen fluoride (HF), and selenium (Se) emissions, and a major source of metallic HAP emissions including As, chromium (Cr), Ni, and others. The discrepancy is even greater now that almost all other major source categories have been required to control Hg and other HAP under CAA section 112. In 2005, U.S. EGUs emitted 50 percent of total domestic anthropogenic Hg emissions, 62 percent of total As emissions, 39 percent of total cadmium (Cd) emissions, 22 percent of total Cr emissions, 82 percent of total HCl emissions, 62 percent of total HF emissions, 28 percent of total Ni emissions, and 83 percent of total Se emissions.[10] Exposure to these HAP, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.*, irritation of the lung, skin, and mucus membranes; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting). Two of the HAP are classified as human carcinogens (As and CrVI) and two as probable human carcinogens (Cd and Ni). *See* 76 FR 25003–25005 for a fuller discussion of the health effects associated with these pollutants.

III. Appropriate and Necessary Finding

A. Overview

In December 2000, the EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under section 112(d). The EPA found that it was appropriate to regulate HAP emissions from coal- and oil-fired EGUs because, among other reasons, Hg is a hazard to public health, and U.S. EGUs are the largest domestic source of Hg emissions. The EPA also found it appropriate to regulate HAP emissions from EGUs because it had identified certain control options that would effectively reduce HAP emissions from U.S. EGUs. The EPA found that it was necessary to regulate HAP emissions from U.S. EGUs under section 112 because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from HAP emissions from U.S. EGUs and that CAA section 112 is intended to address HAP emissions. *See* 76 FR 24984–20985 (for further discussion of 2000 finding).

Because several years had passed since the 2000 finding, the EPA performed additional technical analyses for the proposed rule, even though those analyses were not required. These analyses included a national-scale Hg risk assessment focused on populations with high levels of self-caught fish consumption, and a set of 16 case studies of inhalation cancer risks for non-Hg HAP. The analyses confirm that it remains appropriate and necessary to regulate U.S. EGUs under section 112.

In the preamble to the proposed rule, the EPA reported the results of those additional technical analyses. Those analyses confirmed the 2000 finding that it is appropriate to regulate U.S. EGUs under section 112 by demonstrating that (1) Hg continues to pose a hazard to public health because up to 28 percent of watersheds were estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the reference dose for methylmercury (MeHg RfD), a level above which there is increased risk of neurological effects in children, (2) non-Hg HAP emissions pose a hazard to public health because case studies at 16 facilities demonstrated that lifetime cancer risks at 4 of the facilities exceed 1 in 1 million, and (3) U.S. EGUs remain the largest domestic source of Hg emissions and several HAP (*e.g.*, HF, Se, HCl), and are among the largest contributors for other HAP (*e.g.*, As, Cr, Ni, HCN). Thus, in the preamble to the proposed rule, the EPA found that Hg and non-Hg HAP emissions from U.S. EGUs pose hazards to public health, which confirmed the 2000 finding and demonstrated that it remains appropriate to regulate U.S. EGUs under section 112.

In the preamble to the proposed rule, the EPA also found that it is appropriate to regulate U.S. EGUs because (1) Hg emissions pose a hazard to the environment and wildlife, adversely impacting species of fish-eating birds and mammals, (2) acid gas HAP pose a hazard to the environment because they contribute to aquatic acidification, and (3) effective controls are available to reduce Hg and non-Hg HAP emissions from U.S. EGUs.

The additional analyses reported in the preamble to the proposed rule also confirmed that it remains necessary to regulate U.S. EGU under CAA section 112. These analyses demonstrated that (1) Hg emissions from U.S. EGUs remaining in 2016 are reasonably anticipated to pose a hazard to public health after imposition of other CAA

[10] From 2005 National-Scale Air Toxics Assessment (NATA), available at *http://www.epa.gov/ttn/atw/nata2005/.*

requirements, such as the Cross-State Air Pollution Rule (CSAPR); (2) U.S. EGUs are reasonably anticipated to remain the largest source of Hg in the U.S. and thus contribute to the risk associated with exposure to MeHg; (3) Hg emissions from U.S. EGUs after imposition of the requirements of the CAA were projected to be 29 tons per year in 2016, similar to levels of Hg emitted today, indicating that further substantial reductions in Hg emissions are not reasonably anticipated without federal regulations on Hg from U.S. EGUs; (4) we cannot be certain that the identified cancer risks attributable to non-Hg emissions from U.S. EGUs will be addressed through imposition of the requirements of the CAA because companies can use compliance strategies for criteria pollutants that do not achieve HAP co-benefits (*e.g.*, purchasing allowances in a trading program); and (5) we cannot ensure that Hg and non-Hg HAP emissions reductions achieved since 2005 would be permanent without federally binding regulations for Hg from U.S. EGUs.

Since issuance of the proposed rule, the EPA has conducted peer reviews of the national-scale Hg risk assessment (Hg Risk TSD) and the approach for estimating chromium and nickel inhalation cancer risk in the case studies.[11] [12] The peer review of the Hg Risk TSD was conducted by EPA's independent Science Advisory Board (SAB). The SAB stated that it "supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs." [13] SAB recommended several improvements to the data, methods and documentation of the analyses, which EPA has fully addressed in the revised Hg Risk TSD.

As described in the revised Hg Risk TSD, after addressing comments from the peer review, the revised results show that up to 29 percent of modeled watersheds are estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the MeHg RfD, an increase of one percentage point from the results reported in the proposed rule. We conclude that Hg emissions from EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds at risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone without considering deposition from other sources would lead to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition.[14] [15] Each of these results independently supports our conclusion that Hg emissions from EGUs pose hazards to public health.

The peer review of the approach to estimate Ni and Cr cancer risk in the case studies also supported EPA's assessment. The EPA enhanced this analysis in response to the peer review and public comments. The results of those revised analyses show that 6 of 16 modeled facilities have lifetime cancer risks greater than 1 in a million, thus confirming that non-Hg HAP emissions from U.S. EGUs remain a hazard to public health. Given Congress' determination that categories of sources that emit HAP resulting in a lifetime cancer risk greater than 1 in a million should not be removed from the CAA section 112(c) source category list and should continue to be regulated under CAA section 112, the EPA concludes that risk above that level represents a hazard to public health.

Based on our consideration of the peer reviews, public comments, and our updated analyses, we confirm the findings that Hg and non-Hg HAP emissions from U.S. EGUs pose hazards to public health and that it remains appropriate to regulate U.S. EGUs under CAA section 112. We also conclude that it remains appropriate to regulate U.S. EGUs under CAA section 112 because of the magnitude of Hg and non-Hg emissions, environmental effects of Hg and certain non-Hg emissions, and the availability of controls to reduce HAP emissions from EGUs.

In addition, we conclude that the hazards to public health from Hg and non-Hg emissions from U.S. EGUs are reasonably anticipated to remain after imposition of the requirements of the CAA. The same is true for hazards to the environment. Thus, we confirm that it is necessary to regulate U.S. EGUs under CAA section 112.

B. Peer Review of the Hg Risk TSD Supporting the Appropriate and Necessary Finding for Coal and Oil-Fired EGUs and EPA Response

In the preamble to the proposed rule, the EPA stated that "in making the finding that it remains appropriate and necessary to regulate EGUs to address public health and environmental hazards associated with emissions of Hg and Non-Hg HAP from EGUs, the EPA determined that the Hg Risk TSD supporting EPA's 2011 review of U.S. EGU health impacts should be peer-reviewed." [16] We also indicated that due to the court-ordered schedule for the final rule, we planned to conduct the peer review as expeditiously as possible after issuance of the proposed rule, and that the results of the peer review and any EPA response would be published before the final rule. Due to the extension of the public comment period and the volume of public comments received on the analyses supporting the proposed rule, we were unable to publish EPA's response prior to signature of the final rule.

The EPA's response to the peer review the Hg Risk TSD is fully documented in the revised *Technical Support Document (TSD): National-Scale Assessment of Hg Risk to Populations of High Consumption of Self-Caught Fish In Support of the Appropriate and Necessary Finding for Coal and Oil-Fired Electric Generating Units.*[17] The following sections describe the peer review process that we followed, provide the peer review charge questions presented to the peer review panel, summarize the key recommendations from the peer review, and summarize our responses to those recommendations.

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[11] U.S. EPA. 2011a. *National-Scale Assessment of Mercury Risk to Populations with High Consumption of Self-caught Freshwater Fish In Support of the Appropriate and Necessary Finding for Coal- and Oil-Fired Electric Generating Units.* Office of Air Quality Planning and Standards. November. EPA–452/R–11–009.

[12] U.S. EPA. 2011b. *Supplement to Non-mercury Case Study Chronic Inhalation Risk Assessment for the Utility MACT Appropriate and Necessary Analysis.* Office of Air Quality Planning and Standards. November.

[13] U.S. Environmental Protection Agency-Science Advisory Board (U.S. EPA–SAB). 2011. Peer Review of EPA's Draft National-Scale Mercury Risk Assessment. EPA–SAB–11–017. September. Available on the Internet at *http://yosemite.epa.gov/sab/sabproduct.nsf/BCA23C5B7917F5BF8525791A0072CCA1/$File/EPA-SAB-11-017-unsigned.pdf.*

[14] Because some watersheds with exposures sufficient to exceed the RfD with Hg deposition from U.S. EGUs alone without considering deposition from other sources also have U.S. EGU contributions of more than 5 percent of total Hg deposition, there is some overlap between the two risk metrics. This explains why the total percent of watersheds exceeding either risk metric is less than the sum of the individual risk metrics.

[15] Requiring at least a 5 percent EGU contribution is a conservative approach given the increasing risks associated with incremental exposures above the RfD. Because we are finding 24 percent of watersheds with populations potentially at risk even using this conservative approach, we have confidence that emissions of Hg from U.S. EGUs are causing a hazard to public health.

[16] 76 FR 25012.

[17] U.S. EPA, 2011a.

1. Summary of Peer Review Process

Peer review is consistent with EPA's open and transparent process to ensure that the Agency's scientific assessments and rulemakings are based on the best science available. This regulatory action was supported by the Hg Risk TSD, which is a highly influential scientific assessment. Therefore, the EPA conducted a peer review in accordance with OMB's *Final Information Quality Bulletin for Peer Review*[18] as described below. All the materials related to the peer review, including the SAB's final report, can be found in the docket for this rulemaking.

The EPA commissioned the peer review through EPA's SAB, which provides independent advice and peer review to EPA's Administrator on the scientific and technical aspects of environmental issues. The SAB convened a 22-member peer review committee. The SAB process for selecting the panel began with two **Federal Register** Notices requesting nominations for the *Mercury Review Panel*.[19] Based on nominations received, a list of potential panel members, along with bio-sketches, was posted for public comment on the SAB Web site on April 15, 2011. The members of the *Mercury Review Panel* were announced on May 24, 2011. The membership of the panel included representatives of 16 academic institutions, 4 state health or environmental agencies, 1 federal agency, and 1 utility industry organization.[20] The panel held a public meeting in Research Triangle Park, NC, on June 15–17, 2011, which included the opportunity for public comment on the Hg Risk TSD and the peer review process.[21] At the June 15–17 public meeting, the panel completed a draft peer review report. The minutes of that meeting and the draft peer review report were posted to the SAB public Web site within the public comment period for the proposed rule. The panel discussed the draft report at a public teleconference on July 12, 2011, during which additional opportunities for public comment were provided,[22] and submitted a revised draft for quality review by the Chartered SAB before the end of the public comment period on the rule. The Chartered SAB held a public teleconference on September 7, 2011, to conduct a quality review of the draft report; this teleconference also included a final opportunity for public comment.[23] The SAB submitted its final report to EPA on September 29, 2011.[24] Notice of all the meetings was published in the **Federal Register** and all of the materials discussed at the SAB meetings, including technical documents, presentations, meeting minutes, and draft reports were posted for public access on the SAB Web site[25] and were added to the docket for the final rule on October 14, 2011.

2. Peer Review Charge Questions

The EPA asked the SAB to comment on the Hg Risk TSD, including the overall design and approach and the use of specific models and key assumptions. The EPA also asked the SAB to comment on the extent to which specific facets of the assessment were well characterized in the Hg Risk TSD. The specific charge questions are listed below:

Question 1. Please comment on the scientific credibility of the overall design of the mercury risk assessment as an approach to characterize human health exposure and risk associated with U.S. EGU mercury emissions (with a focus on those more highly exposed).

Question 2. Are there any additional critical health endpoint(s) besides IQ loss, which could be quantitatively estimated with a reasonable degree of confidence to supplement the mercury risk assessment (*see* section 1.2 of the Mercury Risk TSD for an overview of the risk metrics used in the risk assessment)?

Question 3. Please comment on the benchmark used for identifying a potentially significant public health impact in the context of interpreting the IQ loss risk metric (i.e., an IQ loss of 1 to 2 points or more representing a potential public health hazard). Is there any scientifically credible alternate decrement in IQ that should be considered as a benchmark to guide interpretation of the IQ risk estimates (*see* section 1.2 of the Mercury Risk TSD for additional detail on the benchmark used for interpreting the IQ loss estimates)?

Question 4: Please comment on the spatial scale used in defining watersheds that formed the basis for risk estimates generated for the analysis (i.e., use of 12-digit hydrologic unit code classification). To what extent do [Hydrologic Unit Code] HUC12 watersheds capture the appropriate level of spatial resolution in the relationship between changes in mercury deposition and changes in MeHg fish tissue levels? (see section 1.3 and Appendix A of the Mercury Risk TSD for additional detail on specifying the spatial scale of watersheds used in the analysis).

Question 5: Please comment on the extent to which the fish tissue data used as the basis for the risk assessment are appropriate and sufficient given the goals of the analysis. Please comment on the extent to which focusing on data from the period after 1999 increases confidence that the fish tissue data used are more likely to reflect more contemporaneous patterns of Hg deposition and less likely to reflect earlier patterns of Hg deposition. Are there any additional sources of fish tissue MeHg data that would be appropriate for inclusion in the risk assessment?

Question 6: Given the stated goal of estimating potential risks to highly exposed populations, please comment on the use of the 75th percentile fish tissue MeHg value (reflecting targeting of larger but not the largest fish for subsistence consumption) as the basis for estimating risk at each watershed. Are there scientifically credible alternatives to use of the 75th percentile in representing potential population exposures at the watershed level?

Question 7: Please comment on the extent to which characterization of consumption rates and the potential location for fishing activity for high-end self-caught fish consuming populations modeled in the analysis are supported by the available study data cited in the Mercury Risk TSD. In addition, please comment on the extent to which consumption rates documented in Section 1.3 and in Appendix C of the Mercury Risk TSD provide appropriate representation of high-end fish consumption by the subsistence population scenarios used in modeling exposures and risk. Are there additional data on consumption behavior in subsistence populations active at inland freshwater water bodies within the continental U.S.?

Question 8: Please comment on the approach used in the risk assessment of

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[18] Office of Management and Budget (OMB). 2004. *Final Information Quality Bulletin for Peer Review.* December. Available on the Internet at *http://www.whitehouse.gov/omb/memoranda_fy2005_m05-03.*

[19] 76 FR 10896 and 76 FR 17649. The first notice requested nominations to a Clean Air Scientific Advisory Committee (CASAC) panel. Upon review of the scope of the CASAC charter (resulting from a public comment received in response to the first notice), the SAB determined that it would be more appropriate to form a panel under the SAB, rather than CASAC. The second notice announced this change and requested nominations for the SAB panel.

[20] The full list of panel members is documented at *http://yosemite.epa.gov/sab/sabproduct.nsf/0/9F048172004D93BB8525783900503486/$File/Determination%20memo%20with%20addendum-05.24.11.pdf.*

[21] 76 FR 29746.

[22] 76 FR 39102.

[23] 76 FR 50729.

[24] U.S. EPA–SAB, 2011. Peer Review of EPA's Draft National-Scale Mercury Risk Assessment.

[25] *See http://yosemite.epa.gov/sab/sabpeople.nsf/WebCommittees/BOARD.*

assuming that a high-end fish consuming population could be active at a watershed if the "source population" for that fishing population is associated with that watershed (e.g., at least 25 individuals of that population are present in a U.S. Census tract intersecting that watershed). Please identify any additional alternative approaches for identifying the potential for population exposures in watersheds and the strengths and limitations associated with these alternative approaches (additional detail on how EPA assessed where specific high-consuming fisher populations might be active is provided in section 1.3 and Appendix C of the Mercury Risk TSD).

Question 9: Please comment on the draft risk assessment's characterization of the limitations and uncertainty associated with application of the Mercury Maps approach (including the assumption of proportionality between changes in mercury deposition over watersheds and associated changes in fish tissue MeHg levels) in the risk assessment. Please comment on how the output of CMAQ [Community Multiscale Air Quality] modeling has been integrated into the analysis to estimate changes in fish tissue MeHg levels and in the exposures and risks associated with the EGU-related fish tissue MeHg fraction (*e.g.*, matching of spatial and temporal resolution between CMAQ modeling and HUC12 watersheds). Given the national scale of the analysis, are there recommended alternatives to the Mercury Maps approach that could have been used to link modeled estimates of mercury deposition to monitored MeHg fish tissue levels for all the watersheds evaluated? (additional detail on the Mercury Maps approach and its application in the risk assessment is presented in section 1.3 and Appendix E of the Mercury Risk TSD).

Question 10: Please comment on the EPA's approach of excluding watersheds with significant non-air loadings of mercury as a method to reduce uncertainty associated with application of the Mercury Maps approach. Are there additional criteria that should be considered in including or excluding watersheds?

Question 11: Please comment on the specification of the concentration-response function used in modeling IQ loss. Please comment on whether EPA, as part of uncertainty characterization, should consider alternative concentration-response functions in addition to the model used in the risk assessment. Please comment on the extent to which available data and methods support a quantitative treatment of the potential masking effect of fish nutrients (*e.g.*, omega-3 fatty acids and selenium) on the adverse neurological effects associated with mercury exposure, including IQ loss (detail on the concentration-response function used in modeling IQ loss can be found in section 1.3 of the Mercury Risk TSD).

Question 12: Please comment on the degree to which key sources of uncertainty and variability associated with the risk assessment have been identified and the degree to which they are sufficiently characterized.

Question 13: Please comment on the draft Mercury Risk TSD's discussion of analytical results for each component of the analysis. For each of the components below, please comment on the extent to which EPA's observations are supported by the analytical results presented and whether there is a sufficient characterization of uncertainty, variability, and data limitations, taking into account the models and data used: Mercury deposition from U.S. EGUs, fish tissue MeHg concentrations, patterns of Hg deposition with HG fish tissue data, percentile risk estimates, and number and frequency of watersheds with populations potentially at risk due to U.S. EGU mercury emissions.

Question 14: Please comment on the degree to which the final summary of key observations in Section 2.8 is supported by the analytical results presented. In addition, please comment on the degree to which the level of confidence and precision in the overall analysis is sufficient to support use of the risk characterization framework described on page 18.

3. Summary of Peer Review Findings and Recommendations

The SAB was generally supportive of EPA's approach.[26] The SAB concluded, "[i]n summary, based on its review of the draft Technical Support Document and additional information provided by EPA representatives during the public meetings, the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs."[27] The SAB further concluded, "[t]he SAB regards the design of the risk assessment as suitable for its intended purpose, to inform decision-making regarding an 'appropriate and necessary finding' for regulation of hazardous air pollutants from coal and oil-fired EGUs, provided that our recommendations are fully considered in the revision of the assessment."[28]

The SAB report contained many recommendations for improving the Hg Risk TSD, which the SAB organized into three general themes: (1) Improve the clarity of the Hg Risk TSD regarding methods and presentation of results, (2) expand the discussion of sources of variability and uncertainty, and (3) de-emphasize IQ loss as an endpoint. In the following subsection, we provide EPA's response to these recommendations.

4. The EPA's Responses to Peer Review Recommendations

In response to the peer review, the EPA has substantially revised the Hg Risk TSD. The revised Hg Risk TSD addresses all of the recommendations from the SAB and includes a detailed list of the specific revisions made to the Hg Risk TSD. Revisions in response to the main recommendations are summarized below. Italicized statements are the SAB's recommendations, which are followed by EPA's response.

- *The watershed-focus of the Hg Risk TSD should be clearly stated early in the introduction to the document.* We have stated clearly in the introduction to the revised Hg Risk TSD that the focus of the analysis is on scenarios of high fish consumption by subsistence level fishing populations, assessed at watersheds where there is the potential for such subsistence fishing activity. Specifically, we modeled risk for a set of subsistence fisher scenarios at those watersheds where (a) we have measured fish tissue Hg data and (b) it is reasonable to assume that subsistence-level fishing activity could occur. We emphasize the point that the analysis is not a representative population-weighted assessment of risk. Rather, it is based on evaluating these potential exposure scenarios.
- *Because IQ does not fully capture the range of neurodevelopmental effects associated with Hg exposure, analysis of this endpoint should be deemphasized (and moved to an appendix) and primary focus should be placed on the MeHg RfD-based hazard quotient metric.* We modified the structure of the revised Hg Risk TSD accordingly.
- *Clarify the rationale for using a Hazard Quotient (HQ) at or above 1.5 as the basis for selecting potentially impacted watersheds.* The SAB fully supported using HQ as the risk metric, but we revised the discussion in the Hg Risk TSD to clarify why we selected 1.5

[26] U.S. EPA–SAB, 2011.

[27] *Id.*

[28] *Id.*

as the benchmark. We clarified that exposures above the RfD (*i.e.*, an HQ above one) represent increasing risk of neurological health effects.[29] We further clarified that the HQ is calculated to only one significant digit, based on the precision in the underlying RfD calculations. As a result, rounding convention requires that any values at or above 1.5 be expressed as an HQ of 2, while any values below 1.5 (*e.g.*, 1.49) be rounded to an HQ of 1. Thus, MeHg exposures leading to an HQ at or above 1.5 for pregnant women are considered above the RfD and are associated with increased risk of neurological health effects in children born to those mothers.

• *Regarding the fish tissue dataset used in the Hg Risk TSD, clarify which species of Hg is reflected in the underlying samples and discuss the implications of differences across states in sampling protocols in introducing bias into the analysis.* We clarified that in most cases, the fish tissue is measured for total Hg. Furthermore, based on the scientific literature,[30] it is reasonable to assume that more than 90 percent of fish tissue Hg is MeHg. Therefore, we incorporated an Hg conversion factor[31] into our exposure calculations to account for the fraction of total Hg that is MeHg in fish. We also expanded the discussion of uncertainty to address the potential for different sampling protocols across states to introduce bias into the Hg Risk TSD.

• *Additional detail should be provided on the characteristics of the fish tissue Hg dataset, including its derivation and the distribution of specific attributes across the dataset (e.g., number of fish tissue samples and number of different waterbodies in a watershed, number of species reflected across watersheds).* We included additional figures and tables describing the derivation of the watershed-level fish tissue Hg dataset, including the filtering steps applied to the original water body level data and the additional steps taken to generate the watershed-level fish tissue Hg percentile estimates. In addition, we included tables summarizing key attributes of the dataset (*e.g.*, distribution of fish tissue sample size and number of species across the watershed-level estimates).

• *Determine whether there is additional (more recent) fish tissue data for key states including Pennsylvania, New Jersey, Kentucky and Illinois where U.S. EGUs Hg deposition may be more significant.* We expanded the fish tissue dataset by incorporating additional fish tissue data from the National Listing of Fish Advisories (NLFA), which included additional data for four states (MI, NJ, PA, and MN). We also obtained additional data for Wisconsin. These additional data expanded the number of watersheds in the analysis from 2,317 to 3,141, an increase of 36 percent. The additional watersheds improve coverage in areas with high levels of U.S. EGU-attributable Hg deposition, and thus increase our confidence in the overall results of the Hg Risk TSD.

• *Include additional discussion of the potential that the low sampling rates reflected across many of the watersheds may low-bias the 75th percentile fish tissue Hg estimates used in estimating potential exposures. In addition, include a sensitivity analysis using the 50th percentile estimates to provide a bound on the risk.* The SAB expressed support for the use of the 75th percentile fish tissue Hg value in the Hg Risk TSD, while recommending additional discussion of the issue. We provided additional description of the fish tissue dataset, including distribution of sample sizes and fish species across the watersheds, and an improved discussion of uncertainty and potential low bias resulting from estimation of the 75th percentile fish tissue levels. We also included a sensitivity analysis that used the 50th percentile watershed-level fish tissue Hg level. This sensitivity analysis showed that using the 50th percentile estimates resulted in a decrease in the number and percentage of modeled watersheds with populations potentially at-risk from U.S. EGU-attributable MeHg exposures, from 29 percent of watersheds exceeding either risk metric (*i.e.*, MeHg exposure from U.S. EGUs alone exceeds the RfD or total MeHg exposure exceeds the RfD and U.S. EGUs contribute at least 5 percent) in the revised Hg Risk TSD to 26 percent in the sensitivity analysis in the revised Hg Risk TSD.

• *Expand the discussion of caveats associated with the fish consumption rates used in the analysis.* The SAB was generally supportive of the consumption rates used, while recommending additional discussion of caveats. We expanded the discussion of uncertainty related to the fish consumption rates to address the caveats identified by the SAB. The uncertainty discussion now explains (1) that high-end consumption rates for South Carolina reflect small sample sizes, and therefore may be more uncertain, (2) that the consumption surveys underlying the studies are older (*i.e.*, mostly based on survey data from the 1990s) and behavior may have changed (*i.e.*, consumption rates may have changed since the surveys were conducted), and (3) that consumption rates used in the Hg Risk TSD are annualized rather than seasonal rates and thus contribute little to overall uncertainty. None of these sources of uncertainty is associated with a particular directional bias (*e.g.*, neither systematically higher nor lower risk).

• *Verify whether the consumption rates are daily values expressed as annual averages and whether they are "as caught" or "as prepared."* We carefully reviewed the studies underlying the fish consumption rates used in the Hg Risk TSD and verified that the rates are annual averages of the daily consumption rates and that they represent as prepared estimates. We also expanded the explanation of the exposure calculations to describe more completely the exposure factors and equation used to generate the average daily MeHg intake estimates for the subsistence scenarios.

• *Explain the criteria for exclusion of fish less than 7 inches in length from analysis.* We provided the rationale for the 7-inch cutoff for edible fish used in the Hg Risk TSD. Seven inches represents a minimum size limit for a number of key edible freshwater fish species established at the state level. For example, Pennsylvania establishes 7 inches as the minimum size limit for both trout and salmon (other edible fish species such as bass, walleye and northern pike have higher minimum size limits). The impact of the 7-inch cutoff is likely to be quite small, as only 6 percent of potential fish samples were excluded due to this criterion.

• *Identify the number of watersheds excluded from the analysis due to the criterion for excluding watersheds with less than 25 members of a source population.* The SAB was generally supportive of the approach used for identifying watersheds with the potential for subsistence activity, while recommending additional information on the results of applying the approach. We added a figure to illustrate the number of watersheds with fish tissue Hg data used to model risk for each of the subsistence fishing scenarios. For all scenarios except the female subsistence fishing scenario, the exposure scenarios significantly limited the number of

[29] As stated in the preamble to the proposal, based on the current literature, exposures above the RfD contribute to risk of adverse effects.

[30] See the literature summary in Chapter 4 of U.S. EPA. 2000. *Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories.* Office of Science and Technology, Office of Water, Washington, DC EPA 823–B–00–007.

[31] In the Hg Risk TSD accompanying the proposed rule, we assumed that 100 percent of Hg in fish was MeHg. We derived the 0.95 conversion factor for the revised Hg Risk TSD to reflect that most studies show that more than 90 percent of total Hg in fish is MeHg. See Chapter 4 of U.S. EPA, 2000.

watersheds. Because the female subsistence fishing scenario does not differentiate with regard to ethnicity or socio-economic status (SES), we applied this scenario to all regions of the country and to all watersheds with fish tissue Hg data. This reflects our assumption that, given the generalized nature of the female subsistence fishing scenario, it is reasonable to assume that it could potentially occur at any watershed with fish tissue Hg data. The female subsistence fishing scenario included in the revised risk assessment is similar to the high-consuming female scenario included in the Hg Risk TSD.[32] However, the female subsistence fishing scenario is applied to all watersheds, while in the scenario for the high-consuming low-income female angler, we only evaluated watersheds with a population of at least 25 low-income females. The female subsistence fishing scenario provides greater coverage geographically than the high-consuming low-income female scenario. As described in the revised Hg Risk TSD, the EPA made this change in response to SAB's concerns regarding the potential exclusion of watersheds with fewer than 25 individuals and regarding coverage for high-end recreational fish consumption.[33]

• *Enhance the discussion of the assumption of a linear relationship between changes in Hg deposition and changes in fish tissue Hg at the watershed level, including providing citations to more recent studies supporting the proportional relationship between changes in Hg deposition and changes in MeHg fish tissue levels.* The SAB supported the assumption of a linear relationship between changes in Hg deposition and changes in fish tissue Hg at the watershed level, while recommending additional supporting language. We expanded our discussion of the scientific basis for the proportionality assumption and added citations for the more recent studies supporting the assumption. We also expanded the discussion of uncertainties associated with this assumption, including uncertainties related to the potential for sampled fish tissue Hg level to reflect previous Hg deposition, and the potential for non-air sources of Hg to contribute to sampled fish tissue Hg levels. Each of these sources of uncertainty may result in potential bias in the estimate of exposure associated with current deposition. If the fish tissue Hg levels are too high due to either previous Hg deposition or non-air sources of Hg, then the absolute level of exposure attributed to both total Hg deposition and U.S. EGU-attributable Hg deposition will be biased high. However, the percent contribution from U.S. EGUs will not be affected as it depends entirely on deposition. The EPA took steps to minimize the potential for these biases by (1) only using fish tissue Hg samples from after 1999, and (2) screening out watersheds that either contained active gold mines or had other substantial non-U.S. EGU anthropogenic emissions of Hg. The SAB concluded that the EPA's approach to minimizing the potential for these biases to affect the results of the Hg Risk TSD is sound. In addition, we conducted several sensitivity analyses to gauge the impact of excluding watersheds with the potential for non-EGU Hg loading. We found that the estimates of the percent of modeled watersheds with populations potentially at-risk were largely insensitive to these exclusions, suggesting that any potential biases from including watersheds with potential non-air Hg loadings are likely to be small.

• *Additional sources of variability should be discussed in terms of the degree to which they are reflected in the design of the risk assessment and the impact that they might have on risk estimates. These include: (1) The geographic patterns of populations of subsistence fishers, including how this factor interacts with the limited coverage we have for watersheds with our fish tissue Hg data, (2) the protocols used by states in collecting fish tissue Hg data, (3) body weights for subsistence fishing populations and the impact that this might have on exposure estimates, and (4) preparation and cooking methods which affect the conversion of fish tissue Hg levels (as measured) into "as consumed" values.* We expanded the discussion of sources of variability in the revised Hg Risk TSD to more fully address these sources of variability. The Hg Risk TSD quantitatively reflected many aspects of variability, including spatial and temporal variability in Hg emissions, Hg deposition, fish tissue Hg levels, and subsistence behavior. After evaluating the aspects of variability assessed qualitatively in the Hg Risk TSD such as temporal response in fish tissue, we do not believe that quantitatively incorporating any of these aspects would substantially change the risk results given the stated goal of the analysis to identify watersheds where potential exposures to MeHg from self-caught fish consumption could exceed the RfD.

• *Additional sources of uncertainty should be discussed in terms of their potential impact on risk estimates. These include: (1) Emissions inventory used in projecting total and U.S. EGU-attributable Hg deposition, including the projection of reductions in U.S. EGU emissions for the 2016 scenario, (2) air quality modeling with CMAQ including the prediction of future air quality scenarios, (3) ability of the Mercury Maps-based approach for relating Hg deposition to MeHg in fish to capture Hg hotspots, (4) the limited coverage that we have with fish tissue Hg data for watersheds in the U.S. and implications for the Hg Risk TSD, (5) the preparation factor used to estimate "as consumed" fish tissue Hg levels, (6) the proportionality assumption used to relate changes in Hg deposition to changes in fish tissue Hg levels at the watershed-level, (7) characterization of the spatial location of subsistence fisher populations (including the degree to which these provide coverage for high-consuming recreational fishers), and (8) application of the RfD to low SES populations and concerns that this could low-bias the risk estimates.* We expanded the discussion of sources of uncertainty presented in the revised TSD to address more fully these sources of uncertainty and the potential impact on risk estimates. Regarding these eight additional sources of uncertainty, we have (1) evaluated the uncertainties in the emissions and determined that while an important source of uncertainty, we are not able to quantify emissions uncertainty in the risk analysis, but have determined that the emissions inventories and emissions models represent the best available methods for predicting Hg emissions in the U.S., (2) evaluated the uncertainties in the Hg deposition predictions and determined that while an important source of uncertainty, we are not able to quantify uncertainty in Hg deposition in the Hg Risk TSD. Moreover, the CMAQ model used to estimate deposition is based on peer reviewed science and represents the best available method for predicting Hg deposition in the U.S., (3) evaluated the ability of the Mercury Maps-based approach for relating Hg deposition to MeHg in fish to capture Hg hotspots and determined that while finer resolution deposition modeling might reveal additional areas with elevated deposition, the 12 kilometer

[32] In the Revised Hg Risk TSD, this population is also referred to as the "typical female subsistence consumer."

[33] This change led to a very small increase in the number of watersheds with populations potentially at-risk. In the Hg Risk TSD accompanying the proposed rule, approximately 4 percent of modeled watersheds were excluded based on the SES-based filtering criteria.

(km) deposition modeling matches well with the watershed size selected for the analysis, and thus the use of 12 km deposition estimates with the Mercury Maps based approach will not be a large source of uncertainty, (4) evaluated the limited coverage that we have with fish tissue Hg data for watersheds in the U.S. and implications for the Hg Risk TSD and based on the SAB's recommendations, we supplemented the coverage of watersheds by obtaining additional fish tissue Hg samples for areas heavily impacted by U.S. EGU deposition, thus reducing the uncertainty in the analysis, (5) evaluated the uncertainty in the preparation factor and determined that the level of uncertainty is low, and as such would have minimal impact on the risk estimates, (6) evaluated the uncertainty resulting from the proportionality assumption used to relate changes in Hg deposition to changes in fish tissue Hg levels at the watershed-level, and determined, based both on quantitative sensitivity analyses and qualitative assessments, that this source of uncertainty is not likely to greatly influence the results, and is not likely to have a specific directional bias, (7) evaluated the uncertainty related to characterization of the spatial locations of subsistence populations and determined that uncertainty could be reduced by focusing the risk estimates on female subsistence fishing populations, which are assumed to have the potential to fish in all watersheds, in response to SAB's concerns regarding potential exclusion of watersheds with fewer than 25 individuals and (8) evaluated the potential impact of the uncertainty in application of the RfD to low SES populations. The EPA determined that due to the method used in calculating the RfD, we have confidence that the RfD provides protection for low SES populations.

- *Expand the sensitivity analyses (over those included in the original risk assessment) to address uncertainty related to the use of the 75th percentile fish tissue Hg value (at each watershed) as the core risk estimate.* Based on the SAB's recommendation, we added a sensitivity analysis using the median fish tissue Hg estimate (at the watershed level). This sensitivity analysis showed that use of the median fish tissue Hg concentration instead of the 75th percentile resulted in a relatively small decrease (*i.e.*, 10 percent) in the estimates of watersheds with populations potentially at-risk, and did not substantially change the conclusions of the risk assessment.

C. Summary of Results of Revised Hg Risk TSD of Risks to Populations With High Levels of Self-Caught Fish Consumption

Based on the recommendations we received from the SAB, we revised the quantitative analysis of risk to subsistence fishing populations with high levels of fish consumption. Our revision to the quantitative risk results reflects three key recommendations from the SAB, including (1) addition of 824 watersheds based on additional fish tissue Hg sample data we obtained from states and the National Listing of Fish Advisories, (2) application of a 0.95 adjustment factor to the reported fish tissue Hg concentrations to account for the fraction that is MeHg, and (3) inclusion of all watersheds with fish samples that meet the filtering criteria[34] in representing potential exposures associated with increased risk of neurologic health effects for female subsistence fishing populations.

Based on these revisions, our estimates of the number and percent of modeled watersheds with populations potentially at-risk from exposure to EGU-attributable MeHg changed from those presented in the preamble to the proposed rule.[35] For the 99th percentile consumption scenario, the number of watersheds with fish tissue Hg samples where subsistence fishing populations may be at-risk from exposure to EGU-attributable MeHg increased from 672 to 917 (an increase of 36 percent). For this same scenario, the total percent of modeled watersheds with populations potentially at-risk from either risk metric (*i.e.*, MeHg exposure from U.S. EGUs alone exceeds the RfD or total MeHg exposure exceeds the RfD and U.S. EGUs contribute at least 5 percent) increased from 28 percent estimated at proposal to 29 percent after addressing SAB recommendations. The increase in the total percent of modeled watersheds with populations potentially at-risk using the expanded geographic coverage of watersheds provides additional confidence that emissions of Hg from U.S. EGUs pose a hazard to public health. For the 99th percentile consumption scenario, the percent of modeled watersheds with populations potentially at-risk from total potential exposures to MeHg that exceed the RfD and U.S. EGUs contribute at least 5 percent increased from 22 percent to 24 percent. For the 99th percentile consumption scenario, the percent of modeled watersheds with populations potentially at-risk based on Hg deposition from U.S. EGUs alone decreased from 12 percent to 10 percent.

The additional sensitivity analyses conducted in response to the SAB peer review showed that the estimates of the percent of modeled watersheds with populations potentially at-risk are robust to alternative assumptions about both the watersheds included in the analysis and the selection of the 50th percentile or 75th percentile fish tissue Hg level. Sensitivity analyses excluding entire states with the potential for historical loadings of Hg from non-air sources[36] resulted in an increase from 29 percent to 33 percent in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric (*i.e.*, U.S. EGUs alone or total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent). Including only watersheds in the top 25th percentile of U.S. EGU deposition resulted in an increase in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric, from 29 percent to 30 percent. Using the 50th percentile fish tissue Hg level resulted in a decrease in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric, from 29 percent to 26 percent. On balance, these sensitivity analyses do not substantially reduce the percent of modeled watersheds with populations potentially at-risk, and thus confirm the finding that Hg emissions from U.S. EGUs pose a hazard to public health. In fact, given the broader coverage of modeled watersheds in the revised analysis, we have even greater confidence in our finding that Hg

[34] The watersheds were filtered to exclude watersheds that: (a) Were not freshwater, (b) did not have fish sampling data since 2000, (c) did not have fish larger than 7 inches in length, (d) contained active gold mines or (e) had substantial non-air Hg loading.

[35] Since the time of the analyses conducted in support of the proposed rule, the EPA updated IPM modeling to reflect the most recently available information, including public comments and the final CSAPR (see IPM Documentation for further details on these updates, which is available in the docket). Compared to the modeling conducted at proposal, these updates are projected to result in greater reductions in criteria pollutants, and also to have a slightly greater impact on U.S. EGU Hg emissions. Based on the revised projection for 2016, the EPA estimates that U.S. EGUs would emit 27 tons of Hg, as compared to the 29 tons we modeled for the Hg Risk TSD. We do not expect this 2 ton difference to substantially change the mercury risks reported in the preamble to the proposed rule, as this represents less than a 10 percent reduction in Hg emissions.

[36] The SAB noted that areas with substantially elevated fish tissue Hg levels could also be characterized by lakes and rivers with high natural methylation rates, and thus some of the states we excluded for this sensitivity analysis might not have fish tissue Hg levels that reflect non-U.S. EGU Hg loadings.

emissions from U.S. EGUs pose a hazard to public health.

D. Peer Review of the Approach for Estimating Cancer Risks Associated With Cr and Ni Emissions in the U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Hg HAP and EPA Response

As explained in the preamble to the proposed rule, the EPA submitted for peer review its characterization of the chemical speciation for the emissions of Cr and Ni used in the non-Hg HAP inhalation risk case studies. The remaining aspects of the non-Hg HAP case study risk assessments used methods that were previously peer reviewed. Specifically, the methodologies used to conduct the non-Hg case studies are consistent with those used to conduct inhalation risk assessments under EPA's Risk and Technology Review (RTR) program. Because the RTR assessments are considered to be highly influential science assessments, the methodologies used to conduct them were subject to a peer review by the SAB in 2009. The SAB issued its peer review report in May 2010.[37] The report endorsed the risk assessment methodologies used in the program, and made a number of technical recommendations for EPA to consider as the RTR program evolves.

The EPA's case studies identified Cr and Ni emissions as the key drivers of the estimated inhalation cancer risks for EGUs. Because these results hinged on specific scientific interpretations of data used to characterize EGU emissions of Cr and Ni, the EPA conducted a letter peer review of its analysis and interpretation of those data relative to the quantification of inhalation risks associated with Cr and Ni emissions from U.S. EGUs. The following sections describe the peer review process, enumerate the peer review charge questions presented to the peer review panel, summarize the key recommendations from the peer review, and summarize our responses to those recommendations.

1. Summary of Peer Review Process

The EPA asked three independent, external peer reviewers representing government, academic and the private sector to review of the methods for developing inhalation cancer risk estimates associated with emissions of Cr and Ni compounds from coal- and oil-fired EGUs in support of the appropriate and necessary finding. The approaches and rationale for the technical and scientific considerations used to derive inhalation cancer risks were summarized in the draft document entitled, "Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds." The peer reviewers received several charge questions (three questions on Cr and two questions on Ni, which are provided below) on the technical and scientific relevance of the approaches used to develop the inhalation unit risk estimates. The EPA also provided information on Cr speciation profiles for different industrial sources, as well as information on the Ni speciation of PM from oil-fired EGUs.

2. Peer Review Charge Questions

Below, we present the charge questions posed to the peer reviewers to help guide their review and development of recommendations to EPA on key issues relevant to the characterization of risks from EGU emissions containing either Cr or Ni compounds.

The EPA asked three questions regarding Cr and Cr compounds:

Question 1: Do EPA's judgments related to speciated Cr emissions adequately take into account the available Cr speciation data?

Question 2: Has EPA selected the species of Cr (*i.e.*, hexavalent Cr, Cr(VI)) that accurately represents the toxicity of Cr and Cr compounds?

Question 3: Are the assumptions used in past analysis scientifically defensible, and are there alternatives that EPA should consider for future analysis?

The EPA asked two questions regarding Ni and Ni compounds:

Question 1: Do EPA's judgments related to speciated Ni emissions adequately take into account available speciation data, including recent industry spectrometry studies?

Question 2: Based on the speciation information available and on what we know about the health effects of Ni and Ni compounds, and taking into account the existing Unit Risk Estimates (URE) values (*i.e.*, values derived for EPA's Integrated Risk Information System (IRIS), California Environmental Protection Agency (Cal EPA) and Texas Commission on Environmental Quality (TCEQ)), the EPA has provided several approaches[38] to derive unit risk estimates that may be more scientifically defensible than those used in past analyses. Which of the options presented would result in more accurate and defensible characterization of risks from exposure to Ni and Ni compounds? Are there alternative approaches that EPA should consider?

3. Summary of Peer Review Findings and Recommendations

Regarding Cr and Cr compounds, all three reviewers considered Cr(VI) as the species likely to be driving cancer risks based on solid evidence from the health effects database for Cr and Cr compounds. All three authors also considered EPA's use of the average of the range of the available speciation data (*i.e.*, 12 percent and 18 percent Cr(VI) contained in coal- and oil-fired EGUs, respectively) as a reasonable approach for the derivation of default speciation profiles to be used when there is no speciation data available. All reviewers agreed that there is high uncertainty associated with the variability in the speciation data available for Cr (*e.g.*, range of approximately 4 to 23 percent Cr(VI) from coal-fired units). One of the reviewers recommended several additional studies for EPA's consideration; the EPA considered these in finalizing the report.

Regarding Ni and Ni compounds, the reviewers agreed with the views of the international scientific bodies, which consider Ni compounds carcinogenic as a group. One reviewer recommended that the EPA review several additional Ni speciation data that suggests that sulfidic Ni compounds (which the reviewer considered as the most potent carcinogens within the group of all Ni compounds) are present at low levels in emissions from EGUs. In addition, this reviewer pointed out that there is a recently proposed model that may explain the differences in carcinogenic potential across Ni compounds.

4. The EPA's Responses to Peer Review Recommendations

We summarize EPA's basic responses to the peer review comments below, first for Cr-related issues, and second for Ni-related issues, which are reflected in the revised document.[39]

[37] U.S. Environmental Protection Agency—Science Advisory Board (U.S. EPA–SAB). 2010. *Review of EPA's draft entitled, "Risk and Technology Review (RTR) Risk Assessment Methodologies: For Review by the EPA's Science Advisory Board with Case Studies—MACT I Petroleum Refining Sources and Portland Cement Manufacturing". EPA–SAB–10–007. May. Available on-line at: http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/EPA-SAB-10-007-unsigned.pdf.*

[38] See section 3.3 of U.S. Environmental Protection Agency (U.S. EPA). 2011c. *Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds.* Office of Air Quality Planning and Standards. October.

[39] U.S. EPA, 2011c.

a. Cr and Cr Compounds

In agreement with the peer reviewers and based on the health effects information available for Cr, the EPA assigns high confidence in the assumption that Cr(VI) is the carcinogenic species driving the risk of Cr-emitting facilities. In agreement with the reviews, the EPA considers derivation of default speciation profiles based on the mass of Cr(VI) a reasonable approach. As suggested by one of the reviewers, the EPA reviewed two potentially relevant studies, one of which showed coal combustion emissions containing as much as 43 percent Cr(VI),[40] which suggests that the EPA's quantitative approach could actually underestimate Cr(VI) inhalation risks. However, the other study reviewed by EPA on speciation of Cr in coal combustion showed Cr(VI) percentage levels close to detection limits (*i.e.*, 3 to 5 percent of total Cr, which was close to the limit of detection in this study).[41] Thus, the more recent speciation data available is unlikely to reduce the uncertainty of the Cr speciation analyses used by EPA as the bases for risk characterization analysis.

In agreement with the peer reviewers, the EPA also recognizes that the confidence in the default speciation profiles is low because the profiles are based on a limited data set with a wide range of percentages of Cr(VI) across the different samples.

b. Ni and Ni Compounds

Based on the views of the major scientific bodies mentioned above and the peer reviewers that commented on EPA's approaches to risk characterization of Ni compounds, the EPA considers all Ni compounds to be carcinogenic as a group and the EPA does not consider Ni speciation or Ni solubility to be strong determinants of Ni carcinogenicity. These scientific bodies also recognize that based on the data available, the precise Ni compound(s) responsible for the carcinogenic effects in humans is not always clear, and that there may be differences in the potential toxicity and carcinogenic potential across Ni compounds. Nevertheless, studies in humans indicate that various mixtures of Ni compounds (including Ni sulfate, sulfides and oxides, alone or in combination) encountered in the Ni refining industries may cause cancer in humans, and there is no reason to expect anything different from this for mixtures of Ni compounds from other emission sources. One of the reviewers suggested we consider views by some authors that believe that water soluble Ni, such as Ni sulfate, should not be considered a human carcinogen. This view is based primarily on a negative Ni sulfate 2-year rodent bioassay by the National Toxicology Program (NTP) (which is different from the positive 2-year NTP bioassay for Ni subsulfide).[42] [43] [44] One review article identifies the discrepancies between the animal and human data (*i.e.*, from studies of cancers in workers inhaling certain forms of Ni versus inhalation studies suggesting different carcinogenic potential in rodents with different Ni compounds) and states that the epidemiological data available clearly support an association between Ni and increased cancer risk, although the article acknowledges that the data are weakest regarding water soluble Ni. In addition, the EPA identified a recent review[45] that highlights the robustness and consistency of the epidemiological evidence across several decades showing associations between exposure to Ni and Ni compounds (including Ni sulfate) and cancer.

Regarding the second charge question on Ni compounds, two reviewers suggested using the URE derived by the TCEQ[46] for all Ni compounds as a group, rather than the one derived by the Integrated Risk Information System (IRIS, 1991)[47] specifically for Ni subsulfide. The third reviewer did not comment on an alternative approach. Considering this, to develop our primary risk estimate, the EPA decided to use a health protective approach by applying 100 percent of the current IRIS URE for Ni subsulfide, rather than assuming that 65 percent of the total mass of emitted Ni might be Ni subsulfide, as used in previous analyses. We used the IRIS URE value because IRIS values are preferred given the conceptual consistency with EPA risk assessment guidelines and the level of peer review that such values receive. We used 100 percent of the IRIS value because of the concerns about the potential carcinogenicity of all forms of Ni raised by the major national and international scientific bodies, and recommendations of the peer reviewers. Nevertheless, taking into account that there are potential differences in toxicity and/or carcinogenic potential across the different Ni compounds, and given that two URE values have been derived for exposure to mixtures of Ni compounds that are two to three fold lower than the IRIS URE for Ni subsulfide, the EPA also considers it reasonable to use a value that is 50 percent of the IRIS URE for Ni subsulfide for providing an estimate of the lower end of a plausible range of cancer potency values for different mixtures of Ni compounds.

Although this report focused primarily on cancer risks associated with emissions containing Ni compounds, it is important to note that comparative quantitative analyses of non-cancer toxicity of Ni compounds indicate that Ni sulfate is as toxic or more toxic than Ni subsulfide or Ni oxide which does not support the notion that the solubility of Ni compounds is a strong determinant of its toxicity.[48] [49]

E. Summary of Results of Revised U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Hg HAP

Based on the results of the peer review and public comments on the non-Hg case study chronic inhalation risk assessment, we made several changes to the emissions estimates, dispersion modeling, and risk characterization for the modeled case study facilities. Key changes include (1) changes in emissions, (2) changes in stack parameters for some facilities based on new data received during the

[40] Galbreath KC, Zygarlicke CJ. 2004. "Formation and chemical speciation of arsenic-, chromium-, and nickel-bearing coal combustion $PM_{2.5}$," *Fuel Process Technol* 85:701–726.

[41] Huggins FE, Najih M, Huffman GP. 1999. "Direct speciation of chromium in coal combustion by-products by X-ray absorption fine structure spectroscopy," *Fuel Process Technol* 78:233–242.

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public comment period, (3) use of updated versions of AERMOD and its input processors (AERMAP, AERMINUTE, and AERMET), and (4) use of 100 percent of the current IRIS URE for Ni subsulfide to calculate Ni-associated inhalation cancer risks (rather than assuming that the Ni might be 65 percent as potent as Ni subsulfide).

Based on estimated actual emissions, the highest estimated individual lifetime cancer risk from any of the 16 case study facilities was 20 in a million, driven by Ni emissions from the one case study facility with oil-fired EGUs. Of the facilities with coal-fired EGUs, five facilities had maximum individual cancer risks greater than one in a million [50] (the highest was five in a million), with the risk from four due to emissions of Cr(VI) and the risk from one due to emissions of Ni.[51] There were also two facilities with coal-fired EGUs that had maximum individual cancer risks equal to one in a million. All of the facilities had non-cancer Target Organ Specific Hazard Index (TOSHI) [52] values less than one, with a maximum TOSHI value of 0.4 (also driven by Ni emissions from the one case study facility with oil-fired EGUs).

Since these case studies do not cover all facilities in the category, and since our assessment does not include the potential for impacts from different EGU facilities to overlap one another (*i.e.*, these case studies only look at facilities in isolation), the maximum risk estimates from the case studies likely underestimates true maximum risks for the source category.

Based on the fact that six U.S. EGUs were estimated to meet or exceed the CAA section 112(c)(9) criterion of one in a million, EGUs cannot be removed from the list of source categories to be regulated under CAA section 112.

[50] A risk level of 1 in a million implies a likelihood that up to one person, out of one million equally exposed people would contract cancer if exposed continuously (24 hours per day) to the specific concentration over 70 years (an assumed lifetime). This would be in addition to those cancer cases that would normally occur in an unexposed population of one million people.

[51] When the lower end of the cancer potency range for Ni was used to develop risk estimates, 5 of the 16 facilities had maximum cancer risks exceeding 1 in a million, and the maximum individual cancer risk for any single facility fell to 10 in a million.

[52] The target-organ-specific hazard index (TOSHI) is a metric used to assess whether there is an appreciable risk of deleterious (noncancer) effects to a specific target organ due to continuous inhalation exposures over a lifetime. If a TOSHI value is less than or equal to one, such effects are unlikely. For TOSHI values greater than one, there is an increased risk of such effects.

F. Public Comments and Responses to the Appropriate and Necessary Finding

1. Legal Aspects of Appropriate and Necessary Finding

a. History of Section 112(n)(1)(A)

Comment: One commenter provided a detailed history of EPA's regulatory actions concerning EGUs and implementation of CAA section 112(n)(1)(A). The same commenter implies that the EPA's 2000 appropriate and necessary finding and listing of EGUs was flawed because the Agency did not comply with CAA section 307(d) rulemaking process. The commenter sought review of the 2000 notice in the U.S. Court of Appeals for the District of Columbia Circuit, which was dismissed by the D.C. Circuit. *Utility Air Regulatory Group* v. *EPA*, No. 01–1074 (D.C. Cir. July 26, 2001). The commenter then characterizes at length the 2005 EPA action that revised the interpretation of CAA section 112(n)(1)(A) and, which the D.C. Circuit concluded illegally removed EGUs from the CAA section 112(c) list of sources that must be regulated under CAA section 112. *See New Jersey* v. *EPA*, 517 F.3d 574 (D.C. Cir. 2008). The commenter notes that the D.C. Circuit did not rule on the legal correctness or the sufficiency of the factual record supporting EPA's 2000 listing decision or on the factual correctness of EPA's later decision to reverse its CAA section 112(n)(1)(A) determination. The commenter noted further that the D.C. Circuit indicated that the listing decision could be challenged when the Agency issued the final CAA section 112(d) standards pursuant to CAA section 112(e)(4). The commenter concluded by asserting that the Agency could not ignore the history associated with the regulation of EGUs under section 112 and that two earlier dockets—Docket ID. No. A–92–55 and Docket ID. No. EPA–HQ–OAR–2002–0056—are also part of this long rulemaking effort and must be accounted for in conjunction with Docket No. EPA–HQ–OAR–2009–0234 if all pertinent material and comments are to be part of the rulemaking record.

Response: The commenter characterizes the regulatory history of the rule EPA proposed on May 3, 2011. To the extent that characterization is inconsistent with the lengthy regulatory history EPA provided in the preamble to the May 3, 2011 rule, we disagree. We address several of the statements in more detail below.

First, the commenter makes much of the fact that the EPA did not go through CAA section 307(d) notice and comment rulemaking when making the appropriate and necessary finding and listing decision in 2000. However, the commenter's complaint is without foundation. The CAA does not require CAA section 307(d) rulemaking for listing decisions. In fact, CAA section 112(e)(4) specifically provides that listing decisions may only be challenged "when the Administrator issues emission standards for such * * * [listed] category." Second, the commenter challenged the listing decision in the U.S. Court of Appeals for the District of Columbia Circuit (Court) and, on July 26, 2001, the Court granted EPA's motion to dismiss that action based on the plain language of CAA section 112(e)(4). Moreover, in addition to the 2000 notice, the EPA clearly articulated its basis for listing EGUs in this proposed rule, which is consistent with CAA section 307(d), and the commenter was provided an ample opportunity to comment. Finally, the commenter asserts that the rulemaking docket for this action is incomplete because the Agency did not include two earlier dockets—Docket ID. No. A–92–55 and Docket ID. No. EPA–HQ–OAR–2002–0056—for the Section 112(n) Revision Rule, 70 FR 15994 (March 29, 2005), and the reconsideration of the Section 112(n) Revision Rule, 71 FR 33388 (June 9, 2006), respectively. The commenter is incorrect because EPA incorporated by reference the two dockets at issue. *See* EPA–HQ–OAR–2009–0234–3056.

Comment: One commenter stated that the EPA has assessed the public health risks posed by HAP emissions from coal- and oil-fired EGUs for the last 40 years. According to the commenter, throughout that time, the EPA has come to a single repeated conclusion that HAP emissions from EGUs pose little or no risk to public health. Based on this conclusion, the EPA has properly chosen not to require EGUs to install expensive, new pollution control equipment to control HAP emissions. The commenter asserts that, in this proposed rule, the EPA shifts its opinion on the health impacts of EGU HAP emissions 180 degrees and now seeks to impose sweeping regulatory requirements on all power plants. According to the commenter, the EPA's newfound concern about HAP emissions from EGUs is not based on new and different assessments of the public health consequences of EGU HAP emissions but instead on health benefits from the reduction of non-hazardous air pollutants, primarily PM, which the Agency is required to regulate under other provisions of the CAA. One

commenter stated that for decades, the EPA set primary ambient air quality standards that protect public health with an adequate margin of safety, CAA section 109(b)(1), and set secondary standards that are [sic] "requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air," CAA 109(b)(2). The commenter notes that even if EPA now views those past PM standards as inadequate, the EPA has ongoing regulatory proceedings in which it can address any perceived health concerns. The commenter concludes that regulation of EGU HAP emissions under CAA section 112 is an unlawful way to address those concerns.

Response: The commenter is incorrect in its assertion that the Agency has consistently concluded that HAP emissions from EGUs do not present a hazard to public health. In the 2000 finding, the Agency concluded that HAP emissions from coal- and oil-fired EGUs do pose a hazard to public health and determined that it was appropriate and necessary to regulate such units under CAA section 112. As a result of that finding, the EPA added coal- and oil-fired EGUs to the CAA section 112(c) list of source categories for which emission standards are to be established pursuant to CAA section 112(d). Further, in support of the proposed rule, the EPA conducted additional extensive quantitative and qualitative analyses, which confirm that it remains appropriate and necessary to regulate EGUs under CAA section 112. Among other things, those analyses demonstrate that emissions from coal- and oil-fired EGUs continue to pose a hazard to public health. The commenter also fails to note that the EPA found that HAP emissions from EGUs pose a hazard to the environment as well.

The commenter seems confused about the basis for the Agency's appropriate and necessary finding because it maintains that the EPA made the appropriate and necessary finding based on the health co-benefits attributable to PM reductions that will be achieved as a result of the Agency's regulation of HAP emissions from EGUs. Nowhere in the May 2011 proposal does EPA state that it based the appropriate and necessary finding on hazards to public health attributable to PM emissions. The commenter's allegation lacks foundation. The appropriate and necessary finding unmistakably focuses on the hazards to public health and hazards to the environment associated with HAP emissions from EGUs.

Comment: One commenter stated that CAA section 112 required EPA to make a risk-based determination in order to regulate HAP. According to the commenter, the EPA may regulate substances "reasonably * * * anticipated to result in an increase in mortality or increase in serious illness" to a level that protects public health with an "ample margin of safety." According to the commenter, the EPA has regulated a number of HAP emitted from industrial source categories other than EGUs.

As for EGUs, according to the commenter, the EPA found that the combustion of fossil fuels produces extremely small emissions of a broad variety of substances that are present in trace amounts in fuels and that are removed from the gas stream by control equipment installed to satisfy other CAA requirements. The commenter stated that the EPA, in past reviews, found that these HAP emissions did not pose hazards to public health. *See* 48 FR 15076, 15085 (1983) (radionuclides). the commenter further stated that "[i]n the case of Hg specifically, the EPA found that "coal-fired power plants * * * do not emit mercury in such quantities that they are likely to cause ambient mercury concentration to exceed" a level that "will protect public health with an ample margin of safety." 40 FR 48297–98 (October 19, 1975) (Hg); 52 FR 8724, 8725 (March. 19, 1987) (reaffirming Hg conclusion).

According to the commenter, in the late 1980s, the EPA was concerned that its prior risk assessments of individual HAP emissions from fossil-fuel-fired power plants may not reflect the total risks posed by all HAP emitted by those sources. The commenter states that the EPA modeled the risks posed by all HAP emitted by power plants (very much like the analyses the Agency would conduct for the Utility Study ten years later). The commenter asserts that the modeling again failed to identify threats to public health that warranted regulation under an "ample margin of safety" test.

Response: The commenter's statements concerning the pre-1990 CAA are not relevant to the current action. Congress enacted CAA section 112(n)(1) as part of the 1990 amendments to the Act. That provision requires, among other things, that the Agency evaluate the hazards to public health posed by HAP emissions from fossil-fuel fired EGUs. Had Congress concluded, as commenter appears to assert, that HAP emissions from EGUs did not pose a hazard to public health or the environment, it defies reason that Congress would have required EPA to conduct the three studies at issue in CAA section 112(n)(1) (titled "Electric utility steam generating units") and regulate EGUs under section 112 if the Administrator determined in her discretion that it was appropriate and necessary to do so. The Agency complied with the statutory mandates in CAA section 112(n)(1) in conducting the studies and reasonably exercised its discretion in making the appropriate and necessary finding.

We acknowledge that Congress treated radionuclide emissions from EGUs differently. For radionuclides from EGUs (and certain other sources), Congress included CAA section 112(q)(3), which authorizes but does not require the Agency to maintain the regulations of radionuclides in effect prior to the 1990 amendments. The fact that Congress made an exception for radionuclides and no other HAP from EGUs further demonstrates that the HAP-related actions EPA took with regard to EGUs prior to the 1990 amendments to the CAA are not germane.

As for the commenter's statements about Hg emissions from EGUs, we find their conclusions wholly inconsistent with CAA section 112(n)(1). That provision is titled "Electric utility steam generating units," and it directs EPA to conduct two Hg-specific studies. *See* CAA sections 112(n)(1)(B) and 112(n)(1)(C). The commenter's suggestion that the EPA could or should rely on assessments of Hg from EGUs conducted prior to the 1990 amendments is not tenable.

Finally, the commenter stated that the EPA conducted a risk assessment of all HAP from EGUs prior to the 1990 amendments and that the Agency did not identify any HAP that failed the "ample margin of safety" test. The commenter did not cite the study or provide any information to support the statements so we are unable to respond to the alleged study directly; however, the risk assessments conducted in support of the appropriate and necessary finding, as well as the 2000 finding, demonstrate that HAP emissions from EGUs pose hazards to public health and the environment.

b. Interpretation of "Appropriate" and "Necessary"

Comment: One commenter stated that in the preamble to the proposed rule, the EPA sets out its "interpretation of the critical terms in CAA section 112(n)(1)," arguing that this latest interpretation is "wholly consistent with the CAA" and with the Agency's earlier "2000 finding." *See* 76 FR 24976, 24986 (May 3, 2011). The commenter stated that throughout the proposal EPA tries to suggest that it is returning to

some earlier, "correct" interpretation of CAA section 112(n)(1) set forth in its 2000 action. *See, e.g.*, 76 FR 24989 ("The Agency's interpretation of the term 'appropriate' * * * is wholly consistent with the Agency's appropriate finding in 2000"); id. at 24992 ("Our interpretation of the necessary finding is reasonable and consistent with the 2000 finding"). According to the commenter, the EPA did not provide in 2000 any interpretation of what it now characterizes as the "critical terms" of section 112(n)(1). *See, e.g.*, 70 FR 15999 n.13 (the "2000 finding does not provide an interpretation of the phrase 'after imposition of the requirements of the Act' "); id. at 16000/2 (in 2000, the EPA "did not provide an interpretation of the term 'appropriate' "); 76 FR 24992 (the "Agency did not expressly interpret the term necessary in the 2000 finding"). The commenter believes that for that reason alone, it is impossible to credit EPA's assertion that it "appropriately concluded that it was appropriate and necessary to regulate hazardous air pollutants * * * from EGUs" in 2000, and that it is today merely "confirm[ing] that finding and conclud[ing] that it remains appropriate and necessary to regulate these emissions.* * *"[53]

Response: The commenter disagrees with certain statements in the preamble to the proposed rule that provide that the Agency's interpretation of CAA section 112(n)(1) is reasonable and consistent with the 2000 finding. It is difficult to decipher the exact complaint that the commenter has with EPA's proposed rule in this regard, but the commenter does assert that "the Agency did not provide in 2000 any interpretation of what it now characterizes as the "critical terms" of CAA section 112(n)(1)." The commenter's assertion lacks foundation. Although the 2000 finding did not provide detailed interpretations of the regulatory terms at issue, it discussed the types of considerations relevant to the appropriate and necessary inquiry. For example, it is clear that in 2000, the Agency was concerned with the then current hazards to public health and the environment when assessing whether it was appropriate to regulate EGUs under section 112.[54] In addition, when evaluating whether it was necessary to regulate utilities, the Agency stated that it was necessary to regulate HAP emissions from U.S. EGUs under section 112 because the implementation of the other requirements of the Act would not adequately address the serious public health and environmental hazards arising from HAP emissions from EGUs. The Agency also specifically noted that "section 112 is the authority intended to address" hazards to public health and the environment posed by HAP emissions. *Id.*

The detailed interpretation set forth in the preamble to the proposed rule is consistent with the 2000 finding, but EPA does not assert that the interpretation is in any way necessary to support the factual conclusions reached in the 2000 finding. Instead, we noted in the preamble to the proposed rule that our interpretation is consistent with the 2000 finding because in 2005 we interpreted the statute in a manner that was not consistent with the 2000 finding. The commenter has provided no legal support for its position that the Agency erred in interpreting the statute in a manner that is consistent with a prior factual finding.

Comment: Several commenters assert that in the 1990 amendments to the Clean Air Act, Congress directed the EPA to base its determination regarding regulation of fossil-fuel-fired generating units on consideration of any adverse public health effects identified in the study mandated by the first sentence of section 112(n)(1)(A) and that Congress did not dictate in section 112(n)(1)(A) that the EPA must regulate electric utility steam generating units under section 112.

According to the commenters the sponsor of the House bill that became section 112(n)(1)(A) provides an explanation that contradicts the EPA's approach to regulating EGUs:

> Pursuant to section 112(n), the Administrator may regulate fossil fuel fired electric utility steam generating units only if the studies described in section 112(n) clearly establish that emissions of any pollutant, or aggregate of pollutants, from such units cause a significant risk of serious adverse effects on the public health. Thus, * * * he may regulate only those units that he determines—after taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions—have been demonstrated to cause a significant threat of serious adverse effects on the public health.

136 Cong. Rec. H12,934 (daily ed. Oct. 26, 1990) (statement of Rep. Michael Oxley).

The commenters stated that the EPA position is premised on the assumption that "regulation under section 112" necessarily means "regulation under 112(d)" and falsely premised on the assumption that source categories listed by operation of section 112(n)(1)(A) cannot be regulated differently. The commenters conclude that the language of section 112(n)(1)(a) reflects Congress' intent that "regulation of HAP from EGUs was not intended to operate under section 112(d) but was instead intended to be tailored to the findings of the utility study mandated by section 112(n)(1)(A)."

Response: The commenters maintain that the Agency's interpretation of CAA section 112(n)(1) is flawed in many respects. The primary support for one commenter's arguments against EPA's interpretation, including in the comment above, is legislative history in the form of statements from one Congressman, Representative Oxley. The Supreme Court has repeatedly stated that the statements of one legislator alone should not be given much weight. *See Brock* v. *Pierce County*, 476 U.S. 253, 263 (1986) (finding that "statements by individual legislators should not be given controlling effect, but *when they are consistent with the statutory language and other legislative history, they provide evidence of Congress' intent.*") (*emphasis added*) (citation omitted); *Garcia, et al.*, v. *U.S.*, 469 U.S. 70, 78 (1984), citing *Zuber* v. *Allen*, 396 U.S. 168, 187 (1969) (reiterating its prior findings, the Court indicated that isolated statements "are 'not impressive legislative history.' "); *Weinberger, et al.*, v. *Rossi et al.*, 456 U.S. 25, 35 (declining to make a ruling based on "one isolated remark by a single Senator"); *Consumer Product Safety Comm., et al.* v. *GTE Sylvania, Inc., et al.*, 447 U.S. 102, 117–118 (1980) (declining to give much weight to isolated remarks of one Representative); *Chrysler Corp.* v. *Brown, et al.*, 441 U.S. 281, 311 (1979) (finding that "[t]he remarks of a single legislator, even the sponsor, are not controlling in analyzing legislative history."); *Zuber*, 396 U.S. at 186 (concluding that "[f]loor debates reflect at best the understanding of individual Congressmen."); and *U.S.* v. *O'Brien*, 391 U.S. 367, 384 (1968) (in evaluating the statements of a handful of Congressmen, the Court concluded that "[w]hat motivates one legislator to make a speech about a statute is not necessarily what motivates scores of others to enact it. * * *."). As these cases show, the Supreme Court does not give weight to the statements of an individual legislator, except when the statements are supported by other legislative history and the clear intent of the statute. The commenters cited no case law that would support reliance on such limited legislative history.

The commenter has not cited any other legislative history to support

[53] *Id.* at 24,977/3.

[54] 65 FR 79830.

Representative Oxley's statement, and the lack of additional support makes the statement of little utility or import under the case law. In fact, there does not appear to be anything in the House, Senate, or Committee Reports that supports Oxley's statement. The lack of support for Oxley's statement in the Committee Report is particularly telling since, as the commenter notes, the House and Senate bills required different approaches to regulating EGUs under section 112, with the Senate bill requiring EGUs be regulated prior to the Utility Study. In fact, legislative statements from Senator Durenberger, a supporter of the Senate version, demonstrate that others would almost certainly not have agreed with Oxley's interpretation. For example, Senator Durenberger stated, "It seems to me inequitable to impose a regulatory regime on every industry in America and then exempt one category, especially a category like power plants which are a significant part of the air toxics problem."

Senator Durenberger discussed the negotiations with the Administration and the industry push to avoid regulation, including industry arguments for not regulating Hg from U.S. EGUs:

> The utility industry continued to adamantly oppose [regulation under section 112]. First, they argued that mercury isn't much of an environmental problem. But as the evidence mounted over the summer and it became clear that mercury is a substantial threat to the health of our lakes, rivers and estuaries and that power plants are among the principal culprits, they changed their tactic. Now they are arguing that mercury is a global problem so severe that just cleaning up U.S. power plants won't make enough of a difference to be worth it. They've gone from 'we're not a problem' to 'you can't regulate us until you address the whole global problem.' Recasting an issue that way is not new around here. So, it is not a surprise. But it does suggest the direction in which this debate will be heading in the next few years.

136 Cong. Rec. 36062 (October 27, 1990).

Senator Durenberger also explained why the House version was adopted:

> Given that a resolution of the difficult issues in the conference were necessary to conclude work on this bill, the Senate proposed to recede to the House provision which was taken from the original administration bill. It provides for a 3-year study of utility emissions followed by regulation to the extent that the Administrator finds them necessary.

Id.

Senator Durenberger's statements indicate that it is unlikely that he would agree with Oxley's interpretation of CAA section 112(n)(1), a provision that provides the Agency with considerable discretion, and nothing indicates that others in the Senate (or for that matter anyone else in the House) would agree with that interpretation. Given the Supreme Court's views on the use of such limited legislative history, the EPA reasonably declined to consider (or even discuss) the legislative history in the preamble to the proposed rule and we believe it would be improper to ascribe Representative Oxley's statements to the entire Congress.

Moreover, Representative Oxley's statement directly conflicts with the statutory text. Representative Oxley stated that "[the Administrator may regulate only those units that he determines—*after taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions*—have been demonstrated to cause a significant threat of serious adverse effects on the public health." 136 Cong. Rec. H12934 (daily ed. Oct. 26, 1990), reprinted in 1 1990 Legis. Hist. at 1416–17 *(emphasis added).* However, the Utility Study required under CAA section 112(n)(1)(A) directs the Agency to consider the hazards to public health reasonably anticipated to occur after "imposition of the requirements of [the Clean Air Act]." EPA was not required to consider state or local regulations or voluntary emission reduction programs in the Utility Study, and that study is the only condition precedent to making the appropriate and necessary finding.[55]

The legislative history the commenters rely on is not controlling. The Agency believes that it has reasonably interpreted section 112(n)(1)(A), for all the reasons described herein and in the proposal. The commenters also cite Representative Oxley's statements as support for alternative interpretations of CAA section 112(n)(1). We believe that any arguments that rely on such limited legislative history are without merit.

Comment: One commenter stated that the EPA does acknowledge that, in many significant respects, its new interpretation of CAA section 112(n)(1) "differs from that set forth" in the Agency's 2005 rulemaking, but argues that its change of position is permissible. *See* 76 FR 24988/1 ("[T]o the extent our interpretation differs from that set forth in the 2005 Action, we explain the basis for that difference and why the interpretation, as set forth in this preamble, is reasonable."). In support, commenters note that the EPA cites *National Cable & Telecommunication Ass'n* v. *Brand X Internet Services,* 545 U.S. 967 (2005). The commenters agree that it is true that, in *Brand X Internet Services,* the Supreme Court explained that, if an agency "adequately explains the reasons for a reversal of policy," such change is "not invalidating," since the "whole point of Chevron is to leave the discretion provided by the ambiguities of a statute with the implementing agency." 545 U.S. at 981 (internal quotations omitted). The commenters maintain that all Brand X Internet Services was saying is that "[a]gency inconsistency is not a basis for declining to analyze the agency's interpretation under the *Chevron* framework." *Id.*

According to the commenter, it is not enough that the EPA has purported to "explain" why it has abandoned the interpretation of CAA section 112(n)(1) adopted in 2005. The commenter states that under the first step of *Chevron,* the Agency's latest interpretation must still be consistent with congressional intent. *See Chevron* v. *NRDC,* 467 U.S. at 842–43. The commenters state that under the second step of Chevron, if there is discretion for EPA to exercise in interpreting the "critical terms" of CAA section 112(n)(1), the Agency must properly define the range of that discretion and then act reasonably in exercising that discretion. *See Chevron,* 467 U.S. at 843; *see also Village of Barrington, Ill.* v. *Surface Transportation Bd.,* No. 09–1002 (D.C. Cir. Mar. 15, 2011).The commenters allege that the EPA failed to properly define and exercise the scope of its discretion. In each instance, the commenter maintains that the Agency has departed from the correct interpretation of CAA section 112(n)(1) that it adopted in 2005, seizing instead upon a new approach that is contrary to the plain language of the CAA itself, as interpreted after considering the statements of Representative Oxley.

Response: The commenter appears to argue that the EPA's interpretation of CAA section 112(n)(1) is not consistent with the plain language of the statute, implying that the statute is clear and must be evaluated under step one of Chevron. *See Chevron* v. *NRDC,* 467 U.S. 837 842–42 (1984) (finding that when the legislative intent is clear no additional analysis is required).

[55] In addition, the EPA only considered CAA requirements in the Utility Study and this was the correct approach because Congress knew how to require consideration of non-Federal requirements when directing EPA to conduct a study or assessment. See CAA section 112(n)(5) (Congress required EPA to conduct an assessment of hydrogen sulfide from oil and gas extraction activities and provided that the assessment "shall include review of existing State and industry control standards, techniques and enforcement.").

However, as noted above, much of the commenter's argument that the plain language of the statute precludes EPA's interpretation is based on the unpersuasive legislative history discussed above. As explained in the preamble to the proposed rule, the statute directs the Agency to determine whether it is appropriate and necessary to regulate EGUs under section 112. As the D.C. Circuit has held, the terms "appropriate" and "necessary" are very broad terms. Because these terms are broad they are susceptible to different interpretations. We believe we have reasonably interpreted the appropriate and necessary language in section 112(n)(1)(A). To the extent that interpretation differs from the one set forth in 2005, we have fully explained the basis for such changes. *See* 76 FR 24986–24993 (setting forth the Agency's interpretation of section 112(n)(1)).

Furthermore, we properly considered the scope of our discretion in interpreting the statute as explained in detail in the preamble to the proposed rule. We believe the interpretation set forth in the preamble to the proposed rule is consistent with the Act and, therefore, the Agency should be afforded deference pursuant to *National Cable & Telecommunication Ass'n* v. *Brand X Internet Services,* 545 U.S. 967 (2005).

Comment: A number of commenters agreed with the Agency's interpretation of section 112(n)(1) and the terms appropriate and necessary. The commenters also agreed that the EPA's interpretation of that provision was reasonable and consistent with the statute.

Response: We agree with the commenters and appreciate their support.

Comment: One commenter asserts that the EPA's ultimate motivation for rejecting its prior interpretation of CAA section 112(n)(1) and embracing this flawed new approach is made clear from the very outset of the proposal. According to the commenter, the EPA touts the fact that "one consequence" of the MACT rule would be that the "market for electricity in the U.S. will be more level" and "no longer skewed in favor of the higher polluting units that were exempted from the CAA at its inception on Congress' assumption that their useful life was near an end." *See* 76 FR 24979/2. The MACT rule would "require companies to make a decision—control HAP emissions from virtually uncontrolled sources" or else "retire these sometimes 60 year old units and shift their emphasis to more efficient, cleaner modern methods of generation, including modern coal-fired generation." Id.

The commenter stated that this remarkably forthright statement establishes that the underlying basis for EPA's proposal to regulate EGUs under CAA section 112 is not to address any "hazards to public health" that might be attributed to the emission by EGUs of HAP listed under CAA section 112(b). Rather, according to commenter, the EPA is utilizing the regulation of EGUs under CAA section 112 as a means to an entirely different end: To force the imposition of controls that will also have the result of reducing non-HAP emissions (primarily PM) or force the shutdown of those units for which the cost of such controls would be prohibitive. At the same time, according to commenter, the EPA tacitly acknowledges that it cannot hope to make out a case that the regulation of EGU HAP emissions is "appropriate and necessary" within the meaning of CAA section 112(n)(1). The commenter asserts that the only HAP whose health-related benefits EPA quantifies is Hg. Elsewhere, the commenter stated that the EPA contends there are "additional health and environmental effects" attributable to HAP other than Hg, but admits that it has "not quantified" those risks due supposedly to "insufficient information." *See* 76 FR 24999/2. With respect to Hg the commenter stated that the benefits are so questionable and miniscule, some $4 million to $6 million (given a 3 percent discount rate), that compared to the total social costs of the rule (*i.e.,* nearly $11 billion) the rule cannot be justified were EPA properly to interpret CAA section 112(n)(1) and undertake the sort of regulatory analysis Congress intended. The commenter stated that the reason that the EPA touts in this rulemaking the health benefits EPA attributes to the reduction of non-hazardous air pollutants (again, primarily PM), the regulation of which is authorized under provisions of the CAA apart from CAA section 112, is to elide the inconvenient truth regarding the truly trivial nature of the benefits attributable to HAP regulation itself. The commenter concludes that the EPA distorts CAA section 112(n)(1)(A) "beyond all recognition."

One commenter stated that the EPA is directed by CAA section 112(n)(1)(A) to study the "hazards to public health anticipated to occur as a result of emissions" by EGUs of "pollutants listed under subsection (b) of this section"—*i.e.,* HAP and HAP alone. Thereafter, the EPA is authorized to regulate EGU HAP emissions if, and only if, they determine that "such regulation" of HAP emissions is "appropriate and necessary" to address the "hazards to public health" that may be attributable to HAP emissions. According to the commenter, by contrast, in this rulemaking, the EPA has seized upon the fact that the control of EGU HAP emissions will also control non-HAP (such as PM), and then seeks to justify the regulation of HAP emissions based almost entirely on the health benefits of the reductions in non-HAP emissions that would be coincidentally achieved. The commenter believes that this "regulatory sleight-of-hand" runs afoul of congressional intent and is unlawful.

Response: The commenter alleges that the health-related benefits to regulating HAP emissions from EGUs are "questionable and miniscule," and that the only real benefits stem from non-HAP emissions, such as PM. The commenter also implies that regulation of HAP is nothing more than a straw man and that the Agency's ultimate goal is to regulate other pollutants, and specifically PM. These allegations are wholly without merit. The Agency has conducted comprehensive technical analyses that confirm that HAP emissions from EGUs pose a hazard to public health. The analyses are discussed at length elsewhere in this final rule, and a review of the proposed and final rules utterly refutes commenter's assertion that PM reductions form the basis for the appropriate and necessary finding. In addition, the commenter appears to ignore the Agency's findings concerning the hazards to public health and the environment posed by HAP emissions simply because the Agency is not able to quantify many of the benefits associated with reductions of HAP emissions from EGUs or because the estimated HAP benefits that are quantified are small in relation to the co-benefits achieved through reductions in non-HAP air pollutants, such as PM and SO_2, which are surrogates for certain HAP. The Agency is regulating EGUs pursuant to section 112(d) for all of the reasons explained in the preamble and discussed elsewhere in this response to comments. The commenter fails to recognize that the statute neither requires a cost-benefit analysis prior to finding it appropriate and necessary to regulate EGUs, nor requires such analysis prior to setting emission standards. Indeed, Congress expressly precluded consideration of costs when setting MACT floors. As explained below, the EPA does not believe that it is appropriate to consider costs when

determining whether to regulate EGUs under CAA section 112.

Comment: One commenter stated that the EPA has ignored the language and intent of CAA section 112(n)(1)(A), as interpreted based on Representative Oxley's statements, and that the Agency's interpretation of this provision violates step one of Chevron. Under Chevron where the "intent of Congress is clear," that is the "end of the matter," for both the implementing agency and a reviewing court "must give effect to the unambiguously expressed intent of Congress." Chevron, 467 U.S. at 842–43. The commenter asserts that the legislative history of CAA section 112(n)(1)(A) "sheds considerable light on Congress' unique approach to regulation of EGUs under CAA § 112." According to the commenter, on April 3, 1990, the Senate passed S. 1630. The Senate bill would have required EPA to list EGUs under CAA section 112(c) and to regulate them under the MACT provisions of CAA section 112(d). *See* S. 1630 section 301, 3 1990 Legis. Hist. at 4407. Thereafter, the House of Representatives passed a modified version of S. 1630 on May 23, 1990. This House version substantially changed the provisions of CAA section 112 as they applied to EGUs. *See* 1 1990 Legis. Hist. at 572–73. The House version was virtually identical to the current CAA section 112(n)(1)(A), and was ultimately adopted by the conference committee, enacted by Congress and signed into law. According to the commenter, Congress expressly rejected the "list-under-(c)-and-regulate-under-(d)" approach that S. 1630 would have applied to EGUs, and that Congress did choose to apply to other source categories. The commenter stated that the EPA's interpretation that the Agency is "required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d)" (Id. at 24,993/3) fails to take the legislative history into account, and in a footnote, the commenter states that the Agency erred by not addressing the legislative history as it did in the 2005 action.

Response: For the reasons stated above, we believe commenter's reliance on the single statement of one legislator is flawed. In addition, in a footnote the commenter stated that the EPA recognized "that it had to address" the legislative history in its 2005 action, and that the EPA erred in this case because we did not address the legislative history. The commenter cites no case law to support its contention that an Agency must "address" unpersuasive legislative history. Further, in the 2005 action, the EPA relegated to a footnote the Oxley statement that commenter relies on so heavily even though the statement supported the interpretation we provided in that rule. We recognized then what the commenter fails to recognize now, which is that the Agency cannot argue that the meaning of CAA section 112(n)(1)(A) is clear based on the statements of one legislator.

Furthermore, the Agency's interpretation does not violate Chevron Step 1. The terms "appropriate" and "necessary" are ambiguous. The statements of a lone legislator do not transform those ambiguous words into a Chevron Step 1 situation.

Moreover, the commenter's assertion that Congress unambiguously defined the factors to consider in making the appropriate determination is without merit. We fully explain in the preamble to the proposed rule the basis for the Agency's interpretation, and we are not revising that interpretation based on the comments received.

Finally, the EPA notes that the sentence concerning regulation under CAA section 112(d) that the commenter quotes from the preamble states, in full: "Congress did not exempt EGUs from the other requirements of section 112 and, *once listed*, the EPA is required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d), as described above." 76 FR 24993 (*emphasis added*). The EPA discusses requirements to regulate section 112(c) listed sources under section 112(d) in response to other comments.

c. Consideration of Both Environmental Effects and Health Effects From Other Sources

Comment: Several commenters stated that the EPA acts contrary to congressional intent when the Agency considers itself "thereby authorized to consider 'environmental effects' and the effects of HAP emissions from non-EGU sources, in making its 'appropriate and necessary' finding under subparagraph (n)(1)(A)."

Commenters assert that the EPA misreads CAA section 112(n)(1)(B) and (C) to inject environmental effects in the CAA section 112(n)(1)(A) determination. According to one commenter the plain language of CAA section 112(n)(1) establishes that regulation of EGUs is to be predicated solely on "hazards to public health" attributable to HAP emissions. The legislative history providing that the EPA "may regulate [EGUs] only if the studies described in section 112(n) clearly establish that emissions of any pollutant * * * from such units cause a significant risk of serious adverse risk to the public health" confirms that plain language. *See* Oxley Statement at 1416–17. The commenter further stated that nothing on the face of CAA section 112(n)(1)(A) indicates that Congress intended that the EPA should (or must) take into account any additional information that might be developed through the other studies mentioned in subparagraphs (n)(1)(B) and (C) (*i.e.*, the Mercury Study[56] and the NAS Study[57]), such as HAP emissions from non-EGU sources. The commenter also identified other provisions of section 112 that specifically require consideration of environmental effects and states that Congress would have requires such consideration in CAA section 112(n)(1) if it had wanted EPA to consider environmental effects.

The commenter makes a related assertion that the EPA acts contrary to congressional intent by assuming authority to assess the "'hazard to public health or the environment [from] HAP emissions from EGUs alone' or the 'result of HAP emissions from EGUs in conjunction with HAP emissions from other sources'" (citing 76 FR at 24,988/1). According to the commenter, the only evident basis for the Agency's interpretation that, in making its "appropriate and necessary" finding, the EPA can (and should) take into account HAP emissions from sources other than EGUs, is that the Mercury Study authorized by CAA 112(n)(1)(B) references "mercury emissions from * * * municipal waste combustion units, and other sources, including area sources," in addition to EGUs. The commenter asserts, however, that subparagraph (n)(1)(A) identifies the Utility Study as the sole study to inform EPA's "appropriate and necessary" finding. The commenter states that if Congress had intended that the EPA take into account information developed through the Mercury Study, Congress "would not have specified that the EPA was to predicate its 'appropriate and necessary' finding on the 'results of the study required by this subparagraph' (n)(1)(A)."

Commenter also cites to a number of other section 112 provisions that expressly address environmental effects and the commenter states the only conclusion to draw from the inclusion in those provisions and the absence of such language in section 112(n)(1)(A) is that Congress intended public health to be the only basis for the appropriate and necessary finding.

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[56] U.S. EPA. 1997. *Mercury Study Report to Congress*. EPA–452/R–97–003. December.

[57] NAS, 2000.

Response: The commenter again relies in part on the statements of one legislator to attack EPA's reasoned interpretation of an ambiguous statute. To the extent the commenter's arguments rely on this limited evidence, we refer to the response above. As we stated above, CAA section 112(n)(1) is an ambiguous statutory provision; thus, the EPA's interpretation, not commenter's, is entitled to considerable deference if it is a reasonable reading of the statute. *Chevron*, 467 U.S. at 843–44. For the reasons described herein and in the proposal, we believe that we have reasonably interpreted the statutory terms at issue here. The Agency directs attention to section III.A. of the proposed rule, which includes a thorough discussion of the Agency's interpretation of the relevant statutory terms. To the extent the commenters disagree with EPA's interpretations, the EPA refers back to its discussion in the proposal and responds to the comments as follows.

The commenter appears to maintain that the EPA must interpret the scope of the appropriate and necessary finding solely in the context of the CAA section 112(n)(1)(A) Utility Study, such that only hazards to public health and only EGU HAP emissions may be considered. The commenter incorrectly conflates the requirements for the Utility Study with the requirement to regulate EGUs under CAA section 112 if EPA determines it is appropriate and necessary to do so. The commenter concedes that the Agency may consider information other than that contained in the Utility Study, but only to the extent it relates specifically to hazards to public health directly attributable to HAP emissions from EGUs. We agree that we may consider additional information other than that contained in the Utility Study, as we stated in the preamble to the proposed rule, because courts do not interpret phrases like "after considering the results of" in a manner that precludes the consideration of other information. *See United States* v. *United Technologies Corp.*, 985 F.2d 1148, 1158 (2nd Cir. 1993) ("based upon" does not mean "solely);[58] *see also* 76 FR 24988. We further explained in the preamble to the proposed rule that it was reasonable to interpret the scope of the appropriate and necessary finding in the context of all three studies required under CAA section 112(n)(1) because the provision is title "Electric utility steam generating units."[59] The commenter has provided little more than unpersuasive legislative history to support its restrictive interpretation of our authority. *Id.*

The commenter also argues that the statute clearly prohibits the Agency from considering adverse environmental effects or the cumulative effects of HAP emissions from EGUs and other sources based on its claim that the statute is clear when one *properly* considers the legislative history. Again, the commenter has provided no support for its contention other than the statements of one Representative and the improper conflation of the CAA section 112(n)(1)(A) direction on the conduct of the Utility Study and the appropriate and necessary finding. Congress left it to the Agency to determine whether it is appropriate and necessary to regulate EGUs under CAA section 112 and the statute does not limit the Agency to considering only hazards to public health and only harms directly and solely attributable to EGUs.

The commenter stated that Congress specifically told EPA when it wanted EPA to consider adverse environmental effects in CAA section 112 and cites to several provisions of the Act that require consideration of adverse environmental effects. The commenter ignores CAA section 112(n)(1)(B), which directs the Agency to consider adverse environmental effect. In any event, even were we to view section 112(n)(1)(A) in isolation, as the commenter suggests, we still maintain that we can consider adverse environmental effects under 112(n)(1)(A). Nothing in section 112(n)(1)(A) precludes consideration of environmental effects. Congress required the Agency to assess whether it is appropriate and necessary to regulate EGUs under section 112. We believe that adverse environmental effects can be considered in the appropriate analysis. Congress specifically directed the Agency to consider adverse environmental effects when delisting source categories pursuant to section 112(c)(9), and thus we believe it is reasonable to consider such effects when determining whether it is appropriate to regulate such units under section 112, especially given that Congress did not limit our appropriate and necessary inquiry to the Utility Study. See CAA section 112(c)(9)(B)(ii).

Moreover, the other provisions of CAA section 112 that specifically discuss environmental effects have purposes that are distinguishable from CAA section 112(n)(1), and we do not believe one can reasonably draw the conclusion that the commenter does when comparing those provisions to CAA section 112(n)(1)(A). The lack of a requirement to consider environmental effects in CAA section 112(n)(1)(A) does not equate to a prohibition on the consideration of environmental effects as the commenter concludes. The EPA maintains that it reasonably concluded that we should protect against identified or potential adverse environmental effects absent clear direction to the contrary.

Concerning the consideration of the cumulative effect of HAP emissions from EGUs and other sources, we provided a reasonable interpretation of the statute and noted that our interpretation, unlike commenters, does not "ignore the manner in which public health and the environment are affected by air pollution. An individual that suffers adverse health effects as the result of the combined HAP emissions from EGUs and other sources is harmed, irrespective of whether HAP emissions from EGUs alone would cause the harm."[60]

d. Finding for All HAP To Be Regulated

Comment: Several commenters stated that for those EGU HAP for which the Agency makes no CAA section 112(n)(1)(A) determination, their regulation under CAA section 112 is not authorized. For example, one commenter maintains that the Agency could regulate HAP emissions from EGUs under CAA section 112(n). Accordingly, to the extent that the EPA reads CAA section 112, as construed by *National Lime Ass'n*, as compelling it to regulate all HAP emitted by EGUs, should the Agency make an "appropriate and necessary" determination under CAA section 112(n)(1)(A) with respect to a single HAP (*e.g.*, Hg), the EPA stands poised to commit a fundamental legal error that will condemn the final rule on review. Cf., *e.g.*, *PDK Laboratories, Inc.*, 362 F.3d at 797–98; *Holland* v. *Nat'l Mining Ass'n*, 309 F.3d at 817 (where an agency applies a Court of Appeals "interpretation * * * because it believed that it had no choice" and that it "was effectively 'coerced' to do so," then the agency "cannot be deemed to have exercised its reasoned judgment").

Response: We do not agree with the commenter's assertion that Congress intended EPA to regulate only those EGU HAP emissions for which an appropriate and necessary finding is

[58] Several commenters have taken issue with our citation to *United States* v. *United Technologies Corp.* because the language at issue in that case was "based upon" and the language of section 112(n)(1)(A) is "after considering the results of." We believe that, if anything, "based upon" is more prescriptive than "after considering the results of" such that the case supports the Agency's interpretation that additional information other than the Utility Study may be considered in making the appropriate and necessary finding.

[59] 76 FR 24986–87.

[60] 76 FR 24988.

made, and the commenter has cited no provision of the statute that states a contrary position. The EPA reasonably concluded that we must find it "appropriate" to regulate EGUs under CAA section 112 if we determine that a single HAP emitted from EGUs poses a hazard to public health or the environment. If we also find that regulation is necessary, the Agency is authorized to list EGUs pursuant to CAA section 112(c) because listing is the logical first step in regulating source categories that satisfy the statutory criteria for listing under the statutory framework of CAA section 112. *See New Jersey,* 517 F.3d at 582 (stating that "[s]ection 112(n)(1) governs how the Administrator decides whether to list EGUs. * * *"). As we noted in the preamble to the proposed rule, D.C. Circuit precedent requires the Agency to regulate all HAP from major sources of HAP emissions once a source category is added to the list of categories under CAA section 112(c). *National Lime Ass'n* v. *EPA,* 233 F.3d 625, 633 (D.C. Cir. 2000). 76 FR 24989.

The commenter does not explain its issues with our interpretation of how regulation under section 112 works—*i.e.* making a determination that a source category should be listed under CAA section 112(c), listing the source category under CAA section 112(c), regulating the source category under CAA section 112(d), and conducting the residual risk review for sources subject to MACT standards pursuant to CAA section 112(f). Instead, it asserts that our decision is flawed because the interpretation we provided does not account for all the alternatives for regulating EGUs under section 112, and that we have not properly exercised our discretion leading to a fatal flaw in our rulemaking.

The commenter also ignores the language of section 112(n)(1)(A). As explained in the proposed rule, the use of the terms section, subsection, and subparagraph in section 112(n)(1)(A) demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing EPA's action under section 112(n)(1)(A). Congress directed the Agency to regulate utilities "under this section," not "under this subparagraph," and accordingly EGUs should be regulated under section 112 in the same manner as other categories for which the statute requires regulation. Furthermore, the D.C. Circuit Court found that section 112(n)(1) "governs how the Administrator decides whether to list EGUs" and that once listed, EGUs are subject to the requirements of section 112. *New Jersey,* 517 F.3d at 583. Indeed, the D.C. Circuit Court expressly noted that "where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly," noting that "section 112(c)(6) expressly exempts EGUs from the strict deadlines imposed on other sources of certain pollutants." *Id.* Congress did not exempt EGUs from the other requirements of section 112, and once listed, the EPA is reasonably regulating EGUs pursuant to the standard-setting provisions in section 112(d), as it does for all other listed source categories.

The commenter provided no alternative theory for regulating EGUs under CAA section 112, other than to state that the EPA could regulate under CAA section 112(n)(1). However, even assuming for the sake of argument, that we could issue standards pursuant to CAA section 112(n)(1), we would decline to do because there is nothing in section 112(n)(1)(A) that provides any guidance as to how such standards should be developed. Any mechanism we devised, absent explicit statutory support, would likely receive less deference than a CAA section 112(d) standard issued in the same manner in which the Agency issues standards for other listed source categories. We would also decline to establish standards under section 112(n)(1) because Congress did provide a mechanism under CAA sections 112(d) and (f) for establishing emission standards for HAP emissions from stationary sources and it is reasonable to use that mechanism to regulate HAP emissions from EGUs.

e. Considering Costs in Finding

Comment: Several commenters assert that the EPA must consider costs in assessing whether regulation of EGUs is appropriate under CAA section 112(n)(1)(A). Commenters posit that the EPA's position that "the term 'appropriate' * * * does not allow for the consideration of costs in assessing whether hazards * * * are reasonably anticipated to occur based on EGU emissions," 76 FR at 24,989/1, does not withstand scrutiny. According to the commenters, the treatment of "costs" under section 112(c) does not support the Agency's position, and the process by which sources may be "delisted" under section 112(c)(9), including no consideration of costs, sheds no light on the circumstances under which it may be "appropriate" to regulate EGUs under section 112(n)(1)(A).

Commenters characterize as "unintelligible" the EPA's position that it is "reasonable to conclude that costs may not be considered in determining whether to regulate EGUs" when "hazards to public health and the environmental are at issue (citing 76 FR at 24989). "Two commenters stated that a natural reading of the term "appropriate" would include the consideration of costs. According to the commenters, something may be found to be "appropriate" where it is "specially suitable," "fit," or "proper." *See* Webster's Third New International Dictionary at 106 (1993). The term "appropriate" carries with it the connotation of something that is "suitable or proper in the circumstances." *See* New Oxford American Dictionary (2d Ed. 2005). Considering the costs associated with undertaking a particular action is inextricably linked with any determination as to whether that action is "specially suitable" or "proper in the circumstances." One commenter notes that in 2005 (70 FR 15994, 16000; March 29, 2005) the EPA used the dictionary definition of "appropriate," as being "especially suitable or compatible" and that it would be difficult to fathom how a regulatory program could be either "suitable" or "compatible" for a given public health objective without consideration of cost.

One commenter asserts that on the face of CAA section 112(n)(1)(A), it is clear that the EPA is expected to consider costs. According to the commenter, that Congress intended that the EPA investigate and consider "alternative control strategies" for emissions as part of the section 112 (n)(1) Utility Study when making the "appropriate and necessary" determination refutes the notion that the Agency can, and indeed must, disregard the cost of regulation in making that determination, because the cost of a given emission "control strategy" is a central factor in any evaluation of "alternative" controls.

Further, according to commenters, it is well-settled that CAA regulatory provisions should be read with a presumption in favor of considering costs (citing *Michigan* v. *EPA,* 213 F.3d 663, 678 (D.C. Cir. 2000)), and the legislative history of section 112(n)(1)(A) confirms that Congress intended EPA to consider costs (citing Oxley Statement at 1417).

Commenters also assert that the EPA falsely represents that it "did not consider costs when making the "appropriate" determination in the EPA's December 2000 notice (76 FR at 24,989/2).

Response: The commenters first take issue with EPA's explanation of why the Agency determined that costs should not be considered in making the appropriate determination. What

commenters do not identify is an express statutory requirement that the Agency consider costs in making the appropriate determination. Congress treated the regulation of HAP emissions differently in the 1990 CAA amendments because the Agency was not acting quickly enough to address these air pollutants with the potential to adversely affect human health and the environment. *See New Jersey*, 517 F.3d at 578. Specifically, following the 1990 CAA amendments, the CAA required the Agency to list source categories and nothing in the statute required us to consider costs in those listing decision, and we have not done so when listing other source categories. Thus, it is reasonable to make the listing decision, including the appropriate determination, without considering costs.

The commenters next argue that the Agency is compelled by the statute to consider costs based on a dictionary definition of "appropriate" and the CAA section 112(n)(1)(A) direction to consider alternative control strategies for regulating HAP emissions in the Utility Study.

Concerning the definition of "appropriate", commenters stated:

> Not only is it "reasonable" for EPA to consider costs in determining whether it is "appropriate" to regulate EGU HAP emissions, a natural reading of the term indicates that excluding the consideration of costs would be entirely unreasonable. Something may be found to be "appropriate" where it is "specially suitable," "fit," or "proper." *See* Webster's Third New International Dictionary at 106 (1993). The term "appropriate" carries with it the connotation of something that is "suitable or proper in the circumstances." *See* New Oxford American Dictionary (2d Ed. 2005) at 76. Considering the costs associated with undertaking a particular action is inextricably linked with any determination as to whether that action is "specially suitable" or "proper in the circumstances."

The EPA believes the definition of "appropriate" that the commenters provide wholly support its interpretation and nothing about the definition compels a consideration of costs. It is appropriate to regulate EGUs under CAA section 112 because EPA has determined that HAP emissions from EGUs pose hazards to public health and the environment, and section 112 is "specially suitable" for regulating HAP emissions, and Congress specifically designated CAA section 112 as the "proper" authority for regulating HAP emissions from stationary sources, including EGUs. Section 112 of the CAA is "suitable [and] proper in the circumstances" because EPA has identified a hazard to public health and the environment from HAP emissions from EGUs and Congress directed the Agency to regulate HAP emissions from EGUs under that provision if we make such a finding. Cost does not have to be read into the definition of "appropriate" as commenter suggests. In addition, as stated elsewhere in response to comments, the Agency does not consider costs in any listing or delisting determinations, and the EPA maintains that it is reasonable to assess whether to list EGUs (*i.e.* the appropriate and necessary finding) without considering costs.

The commenters' argument that costs must be considered based on the CAA section 112(n)(1)(A) requirement to "develop and describe alternative control strategies" in the Utility Study is equally flawed. The argument is flawed because Congress did not direct the Agency to consider in the Utility Study the costs of the controls when evaluating the alternative control strategies. In addition, the EPA did not consider the costs of the alternative controls in the Utility Study, as implied by the commenter. Thus, even viewing section 112(n)(1)(A) in isolation, there is nothing in that section that compels EPA to consider costs. For the reasons described herein, we do not believe that it is appropriate to consider costs in determining whether to regulate EGUs under section 112.

Additionally, one commenter attempts to refute EPA's statement in the preamble to the proposed rule that the EPA did not consider costs in the 2000 finding by pointing to the only two mentions of cost in that notice. However, the EPA did not say that costs were not mentioned in the 2000 finding and a review of the regulatory finding will show that costs were not considered in the regulatory finding. 65 FR 79830 (December 20, 2000) ("Section III. What is EPA's Regulatory Finding?").

f. Considering Requirements of the CAA in "Necessary"

Comment: Several commenters disagree with EPA's position that it need consider "only those requirements that Congress directly imposed on EGUs through the CAA as amended in 1990," for which "EPA could reasonably predict HAP emission reductions at the time of the Utility Study." According to the commenters, the statutory language of CAA section 112(n)(1) requires that the EPA consider the scope and effect of EGU HAP emissions after the imposition of all of the "requirements" of the CAA, not just the Acid Rain program. The commenter maintains that it would have been easy enough for Congress in subparagraph 112(n)(1)(A) to specify "after imposition of the requirements of Title IV of this chapter," but Congress did not. The commenters further add that the legislative history confirms that Congress meant something much broader than that, providing that the EPA is authorized to regulate EGUs under CAA section 112 only after "taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions." The commenters stated that the CAA's "requirements" include the submission by states of ozone and fine PM attainment demonstrations, as well as SIP provisions needed to reach attainment of the NAAQS because such provisions could include controls on EGUs to reduce SO_2 and NO_X, which controls could also result in a reduction in Hg emissions.

Response: The commenter's characterization of the facts is flawed and its reliance on legislative history that is in direct conflict with the express terms of the statute is unpersuasive.

On the facts, the EPA explained in the preamble to the proposed rule its interpretation of the phrase "after imposition of the requirements of [the Act]" as it related to the conduct of the Utility Study.[61] We reasonably concluded that, since Congress only provided 3 years after enactment to conduct the study, the phrase referred to requirements that were directly imposed on EGUs through the CAA amendments and for which the Agency could reasonably predict co-benefit HAP emission reductions. *Id.* The EPA did not state that the phrase only applied to the Acid Rain program, as commenter asserts, and the Utility Study in fact discussed other regulations, including the NSPS for EGUs and revised NAAQS. With regard to the latter, the EPA ultimately determined that it could not sufficiently quantify the reductions that might be attributable to the NAAQS because states are tasked with implementing those standards. *See* Utility Study, pages ES–25, 1–3, 2–32. Conversely, commenter's position is that the EPA must consider implementation of *all* the requirements of the CAA, but it does not indicate how in conducting the Utility Study the Agency could have possibly considered co-benefit HAP reductions attributable to all future CAA requirements. The Agency appropriately considered the other requirements of the Act in the Utility Study and considered those requirements in determining that it was

[61] 76 FR 24990.

necessary to regulate coal- and oil-fired EGUs in December 2000.

Although not required, the Agency in the preamble to the proposed rule conducted further analyses in support of the 2000 finding. In doing so, we considered a number of requirements that far exceed what Congress contemplated when enacting CAA section 112(n)(1)(A)), and our analyses still show that it remains necessary to regulate coal- and oil-fired EGUs under section 112. 76 FR 24991.

We maintain that we have reasonably interpreted the requirement to consider the hazards to public health and the environment reasonably anticipated to occur after imposition of the requirements of the Act as explained in the preamble to the proposed rule.[62] In addition, as stated above, we also believe it would be reasonable to find it necessary to regulate HAP emissions from EGUs based on our finding that such emissions pose a hazard to public health and the environment today without considering future reductions that we currently project to occur as the result of imposition of CAA requirements that are not yet effective (*e.g.*, CSAPR).

Moreover, Representative Oxley's statement cited by the commenter is not consistent with the express terms of CAA section 112(n)(1)(A) on this issue. Representative Oxley stated that the EPA was to take "into account compliance with all the provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions," but CAA section 112(n)(1)(A) directs the Agency to consider "imposition of the requirements of this chapter," which means the CAA. The Agency reasonably focused on the requirements of the Clean Air Act, which are federally enforceable, and declined to include potential future reductions that may be attributable to voluntary emission reduction programs or state and local regulations that have no basis in the Clean Air Act and are not federally enforceable. In addition to the statutory direction not to consider such requirements, the EPA believes it is reasonable not to include potential reductions attributable to such requirements because the Agency cannot assure that such requirements and the attendant HAP reductions will remain absent regulation under section 112. Finally, the commenter implies that EPA's position is that the Agency will only consider requirements of the Act that directly regulate HAP emissions. The EPA never stated or suggested that interpretation and a fair reading of the proposed rule will demonstrate that EPA considered requirements that achieve co-benefit HAP emission reductions, for example the Transport Rule (known as CSAPR).

Comment: One commenter stated that, under CAA section 112, regulating EGUs is permissible only insofar as it is focused, targeted, and predicated on concrete findings by the Agency that such regulation is indeed "necessary." According to the commenter, the EPA construes CAA section 112(n)(1)(A) as permitting it to find that it is "necessary" to regulate EGUs even where the Agency does not actually know whether it is "necessary" to regulate EGUs. Citing the D.C. Circuit, the EPA suggests that "'there are many situations in which the use of the word 'necessary,' in context, means something that is done, regardless of whether it is indispensible,'" in order to "'achieve a particular end.'" 76 FR 24990, quoting *Cellular Telecommunications* v. *FCC,* 330 F.3d 502, 510 (D.C. Cir. 2003). The commenter stated that in the "context" of CAA section 112(n)(1)(A), as informed by the relevant legislative history from Representative Oxley, it is clear that regulation of EGU HAP emissions can be considered "necessary" only if EPA were to "clearly establish" that such regulation was effectively "indispensible" to address the identified harm. As EPA concedes that it has made no such determination here, its proposal is fatally flawed for that reason alone.

The commenter further asserts that the EPA erred when it concluded that it may " 'determine it is necessary to regulate under section 112' when the Agency is 'uncertain whether imposition of the requirements of the CAA will address the identified hazards'" (citing 76 FR at 24,991/3). According to the commenter, the EPA "cannot take refuge in its own 'uncertainty' to support a finding that it is 'necessary' to regulate EGUs under section 112, and the Act precludes the EPA from '"err[ing] on the side of regulation'" in face of uncertainty (*id.*). The commenter also implies that the finding was based on non-HAP emissions.

Response: The commenter again relies on the legislative statements of one Representative and asserts that the statements are controlling. The EPA disagrees with commenter and maintains that its interpretation of the term "necessary" is reasonable. 76 FR 24990–92 (Section III.A.2.b of the preamble to the proposed rule contains the EPA's interpretation of the term "necessary".) 76 FR 24990–92 (Section III.A.2.b of the proposed rule contains EPA's interpretation of the term "necessary".) The commenter also, in a footnote, implies that EPA based the appropriate and necessary finding on non-HAP air pollution. The commenter is wrong as explained in more detail above.

As an initial matter, this comment is only addressing one aspect of the Agency's interpretation of the term necessary. As EPA stated at proposal:

> If we determine that the imposition of the requirements of the CAA will not address the identified hazards, EPA must find it necessary to regulate EGUs under section 112. Section 112 is the authority Congress provided to address hazards to public health and the environment posed by HAP emissions and section 112(n)(1)(A) requires the Agency to regulate under section 112 if we find regulation is "appropriate and necessary." If we conclude that HAP emissions from EGUs pose a hazard today, such that it is appropriate, and we further conclude based on our scientific and technical expertise that the identified hazards will not be resolved through imposition of the requirements of the CAA, we believe there is no justification in the statute to conclude that it is not necessary to regulate EGUs under section 112.

76 FR 24991.

The EPA has determined that the imposition of the requirements of the CAA will not address the hazards to public health or hazards to the environment that EPA has identified; therefore, it is necessary to regulate EGUs under CAA section 112.

The EPA further interpreted the statute to allow the Agency to find that it is necessary to regulate EGUs under other circumstances, and it is with one of our additional interpretations that commenter takes issue. Specifically, the commenter argues that EPA's interpretation authorizes the Agency to find it necessary to regulate EGUs when we are uncertain it is necessary, but that misconstrues our interpretation and the record. At proposal, the EPA stated:

> In addition, we may determine it is necessary to regulate under section 112 even if we are uncertain whether the imposition of the requirements of the CAA will address the identified hazards. Congress left it to EPA to determine whether regulation of EGUs under section 112 is necessary. We believe it is reasonable to err on the side of regulation of such highly toxic pollutants in the face of uncertainty. Further, if we are unsure whether the other requirements of the CAA will address an identified hazard, it is reasonable to exercise our discretion in a manner that assures adequate protection of public health and the environment. Moreover, we must be particularly mindful of CAA regulations we include in our modeled estimates of future emissions if they are not

[62] 76 FR 24990.

final or are still subject to judicial review ([*e.g.*], the Transport Rule). If such rules are either not finalized or upheld by the Courts, the level of risk would potentially increase. *Id.*

The CAA requires EPA to exercise its discretion in determining whether regulation under section 112 is necessary, and the D.C. Circuit has stated that "there are many situations in which the use of the word 'necessary,' in context, means something that is done, regardless of whether it is indispensible, to achieve a particular end." *See Cellular Telecommunications & Internet Association, et al.* v. *FCC,* 330 F.3d 502, 510 (D.C. Cir. 2003). The EPA's interpretation of "necessary" is reasonable in the context of CAA section 112(n)(1)(A).

The commenter stated that EPA concedes that the Agency has not "clearly established" that regulation of HAP emissions under CAA section 112 is "indispensible." The EPA has conceded nothing but, more importantly, the supposed standard that the commenter presents for evaluating whether it is necessary to regulate HAP emissions from EGUs is not required by the statute. Even the limited legislative history on which the commenter incorrectly relies does not espouse such a standard. The commenter specifically takes issue with EPA's statement that the Agency may find it is necessary to regulate EGUs under CAA section 112 if we are "uncertain whether imposition of the other requirements of the CAA will sufficiently address the identified hazards." 76 FR at 24990. The commenter has again misinterpreted the Agency's position by stating that "EPA construes CAA section 112(n)(1)(A) as permitting it to find that it is "necessary" to regulate EGUs even where the Agency does not actually know whether it is "necessary" to regulate EGUs." Instead, the EPA maintains that it may be necessary to regulate EGUs under CAA section 112 if we identify a hazard to public health or the environment that is appropriate to regulate today and our projections into the future do not clearly establish that the imposition of the requirements of the CAA will address the identified hazard in the future. Making a prediction about future emission reductions from a source category is difficult for statutory provisions that do not mandate direct control of the given source category or pollutants of concern. We maintain that erring on the side of caution is appropriate when the protection of public health and the environment from HAP emissions is not assured based on our modeling of future emissions.

Furthermore, as we stated in the preamble to the proposed rule, we believe it would be reasonable to find it appropriate *and* necessary to regulate EGUs under section 112 today based on a determination that HAP emissions from EGUs pose a hazard to public health and the environment without considering future HAP emission reductions. 76 FR 24991, n.14. We maintain this is reasonable because "Congress could not have contemplated in 1990 that EPA would have failed in 2011 to have regulated HAP emissions from EGU's where hazards to public health and the environment remain." *Id.* The phrase "after imposition of the requirements of [the Act]" as contemplated CAA section 112(n)(1)(A) could be read to apply only to those requirements clearly and directly applicable to EGUs under the 1990 CAA amendments, all of which have been implemented and still hazards to public health and the environment from HAP emissions from EGUs remain.

g. Listing EGUs Under 112

Comment: One commenter stated that even if EPA were to establish under CAA section 112(n)(1)(A) that it is "appropriate and necessary" to regulate HAP emissions from EGUs, regulating those emissions in the form of a MACT standard established pursuant to CAA section 112(d) is contrary to the plain language of the Act. According to the commenter, if EPA proceeds to finalize the proposal and adopts such a standard, the rule will for this reason alone be "dead-on-arrival". According to the commenter, the EPA apparently believes that its only option in regulating EGU HAP emissions is establishing a MACT standard under CAA section 112(d). In the preamble to its proposal, the commenter states that EPA contends that, "once the appropriate and necessary finding is made," EGUs are then "subject to section 112 in the same manner as other sources of HAP emissions"—*i.e.,* by "listing" EGUs under CAA section 112(c) and adopting a MACT standard under CAA section 112(d). *See* 76 FR 24993/2 (emphasis added). The commenter further stated that, given that Congress "directed the Agency to regulate utilities 'under this section' [*i.e.,* CAA section 112]," EPA continues, it follows that "EGUs should be regulated in the same manner as other categories for which the statute requires regulation." Id. (emphasis added). The commenter asserts that as EPA sees it, because "Congress did not exempt EGUs from the other requirements of section 112," once EGUs were "listed" under CAA section 112(c), the Agency was "required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d)." Id. at 24,993/3 (emphasis added).

The commenter stated that, in support of this reading of the CAA, the EPA invokes the decision of the U.S. Court of Appeals for the D.C. Circuit in *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). The commenter further alleged that, according to EPA, the D.C. Circuit has "already held that section 112(n)(1) 'governs how the Administrator decides whether to list EGUs.'" *See* 76 FR 24993/2–3, quoting 517 F.3d at 583. The commenter stated that EPA construes that holding as indicating that, "once listed, EGUs are subject to the requirements of section 112"—including, the EPA presumes, CAA section 112(d). Id. The commenter stated that elsewhere, the EPA construes CAA section 112(n)(1) (A) as "govern[ing] how the Administrator decides whether to list EGUs for regulation under section 112," and quotes the D.C. Circuit's observation in *New Jersey* that "Section 112(n)(1) governs how the Administrator decides whether to list EGUs; it says nothing about delisting EGUs." *See* 76 FR 24981/2, quoting 517 F.2d at 582.

The commenter asserts that EPA misinterprets the "under this section" language of CAA section 112(n)(1); overstates the significance of the *New Jersey* decision; and, as a consequence, misapprehends the scope of its own discretion to formulate regulatory standards for EGUs under CAA section 112. In light of these errors, the commenter maintains that EPA should withdraw the proposed MACT rule.

One commenter stated that if Congress had intended that EPA regulate EGU HAP emissions only through a MACT standard, Congress could have—and presumably would have—directed the Agency to regulate EGU emissions "under CAA section 112(d)." Thus, the commenter maintained that EPA's authority to regulate EGU HAP emissions is not derived from any particular subsection of CAA section 112. Rather, the commenter stated that EPA is authorized to regulate "under this section"—*i.e.,* CAA section 112 generally—as may be "appropriate and necessary." The commenter stated that there is nothing on the face of CAA section 112(n)(1)(A) that specifies that regulation of EGUs must occur under CAA section 112(d). To the contrary, according to the commenter, a plain reading of CAA section 112(n)(1)(A), as interpreted based on the Oxley statement, indicates that establishing a

MACT standard for EGUs under CAA section 112(d) is not what Congress had in mind at all.

Response: We do not agree with the commenter. The EPA interpreted CAA section 112(n)(1)(A) in a manner that gives meaning to all the words used in the provision. *See NRDC* v. *EPA,* 489 F.3d 1364, 1373 (D.C. Cir. 2007) (admonishing EPA for an interpretation of CAA section 112(c)(9) that ignored certain words and the context in which they were used. The Court stated that "EPA's interpretation would make the words redundant and one of them 'mere surplusage,' which is inconsistent with a court's duty to give meaning to each word used by Congress.") (*citing TRW Inc.* v. *Andrews, 534 U.S. 19, 31, 122 S. Ct. 441, 151 L. Ed. 2d 339 (2001)).* Specifically, in the preamble to the proposed rule, we stated:

> The statute directs the Agency to regulate EGUs under section 112 if the Agency finds such regulation is appropriate and necessary. Once the appropriate and necessary finding is made, EGUs are subject to section 112 in the same manner as other sources of HAP emissions. Section 112(n)(1)(A) provision provides, in part, that: '[t]he Administrator shall perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of pollutants listed under subsection (b) of this section after imposition of the requirements of this chapter. * * * The Administrator shall regulate electric utility steam generating units *under this section,* if the Administrator finds such regulation is appropriate and necessary after considering the results of the study required *by this subparagraph.*" *Emphasis added.*

In the first sentence, Congress described the study and directed the Agency to evaluate the hazards to public health posed by HAP emissions listed *under subsection* (b) (*i.e.,* CAA section 112(b)). The last sentence requires the Agency to regulate *under this section* (*i.e.,* CAA section 112) if the Agency finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph (i.e., CAA section 112(n)(1)(A)). The use of the terms "section", "subsection", and "subparagraph" demonstrates that Congress was consciously distinguishing the various provisions of CAA section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs if the Agency finds it appropriate and necessary to do so. Congress directed the Agency to regulate utilities "under this section," and accordingly EGUs should be regulated in the same manner as other categories for which the statute requires regulation. *See* 76 FR 24993.

We maintain that our interpretation of the statute gives meaning to all the words, and the commenter's interpretation does not give any particular meaning to the requirement to "regulate under this section [112]". The commenter is correct that Congress could have in CAA section 112(n)(1)(A) directed EPA to regulate HAP from EGUs under CAA section 112(d) after making the appropriate and necessary finding, but the commenter presumes too much when it stated that Congress would have directed the Agency to regulate HAP emissions from EGUs in such a manner if that is what Congress wanted, simply by including the phrase "regulate under this paragraph" or "regulate under this subparagraph" instead of directing the Agency to "regulate under this section". It did not do so.

As we explained in the section II.A. of the proposed rule, CAA section 112 establishes a mechanism to list and regulate stationary sources of HAP emissions. 76 FR 24980–81. Regulation under CAA section 112 generally requires listing under CAA section 112(c), regulation under CAA section 112(d), and, for sources subjected to MACT standards, residual risk regulations under CAA section 112(f) (as necessary to protect human health and the environment with an ample margin of safety). A determination that EGUs should be listed once the prerequisite appropriate and necessary finding is made is wholly consistent with the language of section 112(n)(1)(A), and listed sources must be regulated under CAA section 112(d). *See* CAA section 112(c)(2); *see also New Jersey,* 517 F.3d at 583 (112(n)(1)(A) "governs how the Administrator decides whether to list EGUs").

As noted above, Congress used the terms section, subsection, and subparagraph in section 112(n)(1)(A). The use of these three terms demonstrates that Congress was consciously distinguishing between the various provisions of section 112. Congress directed the Agency to regulate utilities "under this section," and accordingly EGUs should be regulated in the same manner as other categories for which the statute requires regulation.

Furthermore, the flaws in the commenter's interpretation are highlighted by other CAA section 112 provisions wherein Congress provided specific direction as to the manner of regulation. For example, CAA section 112(m)(6) requires the Administrator to determine "whether the other provisions of *this section* [112] are adequate" and also indicates that "[a]ny requirements promulgated pursuant to this *paragraph* * * * shall only apply to the coastal waters of the States which are subject to [section 328 of the CAA]." (*emphasis added*).

In addition, CAA section 112(n)(3) provides that when the Agency is "promulgating any standard under this section [112] applicable to publicly owned treatment works, the Administrator may provide for control measures that include pretreatment of discharges causing emissions of hazardous air pollutants and process or product substitutions or limitations that may be effective in reducing such emissions." Finally, CAA section 112(n)(5) directs the Agency to assess hydrogen sulfide emissions from oil and gas extraction and "develop and implement a control strategy for emissions of hydrogen sulfide to protect human health and the environment * * * *using authorities under [the CAA] including [section 111] of this title and this section [112].*" (*emphasis added*). We believe these provisions provide ample evidence that Congress knew how to alter or caveat regulation under CAA section 112 when that was its intent. For these reasons, we believe commenter's argument is without merit.

Comment: Two commenters stated that CAA section 112(n)(1)(A) does not specify that regulation of EGUs must proceed under CAA section 112(d). According to the commenter, an argument could be made, therefore, that the CAA accords EPA with the discretion to regulate EGUs using strategies other than emission standards in CAA section 112(d). The commenters also state that section 112(n)(1)(A) of the CAA requires that EPA "develop and describe" alternative control strategies for emissions which may warrant regulation under CAA section 112. According to the commenters if Congress meant for EPA to have one sole regulatory option, i.e., regulation of EGUs only under CAA section 112(d), then the development of alternative control strategies would be rendered meaningless because under CAA section 112(d)(3), the EPA is required to determine the level of control that is achieved by the best performing existing units for which it has data and then to impose that level of control on all existing units. The commenter further states that the development of "alternative control strategies" has no role to play in this process. One commenter does note that the consideration of "alternative" controls becomes relevant, if at all, only in those circumstances where EPA might seek to establish a "Beyond-the-Floor" MACT standard pursuant to CAA section 112(d)(2).

Response: The commenters are correct that CAA section 112(n)(1)(A) directed the Agency to develop and describe in the Utility Study report to Congress alternative control strategies for HAP emissions from EGUs that may warrant regulation in the Utility Study, but the commenters' interpretation of and conclusion based on that language are both factually and legally inaccurate.

The commenters appear to interpret the word "alternative control strategies" to mean something other than the traditional control technologies and control measures that are used to control HAP emissions from EGUs. We do not believe that is a reasonable interpretation of the statute, and the Agency did not interpret the statute in that manner when it conducted the Utility Study. In Chapter 13 of the Utility Study, the EPA considered a range of control measures that would reduce the different types of HAP emitted from EGUs. *http://www.epa.gov/ttn/atw/combust/utiltox/eurtc1.pdf.* The EPA considered pre-combustion controls such as coal washing, fuel switching, and gasification; combustion controls such as boiler design; post-combustion controls such as fabric filters, scrubbers, and carbon absorption; and alternative controls strategies such as demand-side management, energy conservation, and use of alternative fuels (*e.g.*, biomass) or renewable energy. The options discussed in the Utility Study for controlling HAP emissions from EGUs are almost universally available to comply with a CAA section 112(d) standard.

Given the manner in which the Agency conducted the Utility Study, the EPA interpreted the statutory direction as a requirement to set forth the potential alternative control options available to EGUs to comply with CAA section 112 standards in the event the Agency determined regulation under section 112 was appropriate and necessary. The EPA's development and discussion in the Utility Study of alternative control strategies for complying with the standards would help prepare EGUs to comply with the standards if promulgated. Thus, the EPA interpreted the direction to address control strategies in the Utility Study as a request to identify the controls available to EGUs for addressing HAP emissions, and such information would, of course, be relevant if EPA determined that such emissions warranted regulation under section 112.

Furthermore, the EPA establishes CAA section 112(d) standards for stationary sources and it is the responsibility of the sources to comply with the standards using any mechanism available, including pre-combustion and post-combustion measures. Also, the establishment of a MACT standard under CAA section 112(d)(2) and (3) is a two-step process. In the first step, the Agency establishes a floor based on the performance of the best controlled unit or units. *See* CAA section 112(d)(3). In the second step, the Agency must consider additional measures that may reduce HAP emissions and adopt such measures if reasonable after considering costs and non-air quality health and environmental effects. *See* CAA section 112(d)(2). Under the second step, the Agency can consider any measure that reduces HAP emissions even if no source in the category is employing the option under consideration. So, even under the commenter's flawed interpretation of "alternative control strategies", the direction in CAA section 112(n)(1)(A) is not a "pointless exercise" for the development of CAA section 112(d) standards as the Agency considers relevant technologies and HAP emission reduction approaches in evaluating whether to set a more stringent beyond the floor standard.

Comment: One commenter points to CAA section 307(d)(1)(C) and notes that CAA section 112(n) is listed among the provision for which the rulemaking requirements of CAA 307(d) apply. Commenter maintains that this inclusion creates an expectation under the statute that EPA may establish regulatory standards under CAA 112(n). The commenter points to CAA sections 112 (n)(1), (n)(3), and (n)(5) and states that those provisions specifically discuss regulation under CAA section 112 and that EPA must explain why CAA 307(d)(1)(C) states "any regulation under" CAA 112(n) to defend regulation of utilities under section 112(d). The commenter then implies that EPA erred by not even mentioning this provision at proposal.

The commenter also takes issue with EPA's statement in the proposed rule that "use of the terms section, subsection, and subparagraph" "demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs," if EPA determines that it is appropriate and necessary to regulate EGUs. See 76 FR at 24,993/2.

One commenter does not agree with the EPA's finding that the word "subsection" in the first sentence of CAA section 112(n)(1)(A) demonstrates that Congress was consciously distinguishing between the various provisions of CAA section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs," were the EPA to "find[ ] it appropriate and necessary to do so." *See* 76 FR 24993/2. According to the commenter, the only evident reason that the word "subsection" is used in the first sentence of CAA section 112(n)(1)(A) is because the reference is made to the "pollutants" which the Utility Study is to address—*i.e.*, the "pollutants" that are emitted by EGUs and which are "listed under subsection (b)" of CAA section 112. Similarly, the word "subparagraph" is used in the last sentence of CAA section 112(n)(1)(A) to identify "the study" which the EPA is directed to undertake by subparagraph (A) of CAA section 112(n)(1)—*i.e.*, the Utility Study. That the last sentence of subparagraph (n)(1)(A) also states that EPA "shall regulate electric utility steam generating units under this section" does not even imply—much less expressly communicate—that regulation "under this section" must mean "regulation under section 112(d)." The commenter stated that Congress was "consciously distinguishing" between the "various provisions of section 112" for the sake of clarity in the drafting of CAA section 112(n).

The commenter also asserts that the EPA mistakenly relies on section 112(c)(6) when the EPA states that "'where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly. Congress did not exempt EGUs from the other requirements of section 112,'" and thus the Agency is "'required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d)'" (citing 76 FR at 24,993 (internal quotation omitted)).

According to the commenter, nothing in section 112(c)(6) indicates how (or even whether) EGU HAP emissions should be regulated under section 112; paragraph (c)(6) serves only to reiterate that the regulation of such emissions is to occur (if at all) as is provided by section 112(n)(1). The commenter also asserts that the EPA mistakenly relies on *New Jersey.* According to the commenter, the D.C. Circuit in that case did not indicate that the language of section 112(c)(6) should, or could, be construed to mean that EGUs must be regulated under a MACT standard adopted pursuant to section 112(d).

Response: The commenter makes a number of arguments that appear to take issue with the EPA's determination that EGUs should be regulated under CAA section 112(d) if the Agency determines that regulation of HAP emissions from such units is appropriate and necessary.

The commenter implies that the EPA erred because alternative mechanisms for regulation of EGUs under CAA section 112 might exist. We do not agree.

The commenter's argument that the EPA erred because we did not explain why section CAA section 307(d)(1)(C) contemplates regulations under CAA section 112(n) is without merit. It is correct that the Agency believes EGUs should be regulated in the same manner as other sources if the appropriate and necessary finding is made because of the structure of CAA section 112. Nothing in CAA section 112(n)(1) requires or implies that the Agency should or must establish standards for EGUs under that provision. Furthermore, unlike CAA sections 112(n)(3) and 112(n)(5) that commenter cites, CAA section 112(n)(1)(A) does not provide any guidance concerning the manner in which EPA is authorized or required to regulate sources under CAA section 112. *See* CAA section 112(n)(3) (specifically authorizing identified control measures and other requirements for consideration in issuing standards under CAA section 112); see also CAA section 112(n)(5) (directing the Agency to develop and implement a control strategy for emissions of hydrogen sulfide using any authority available under the CAA, including sections 112 and 111, if regulation is appropriate). For these reasons, we disagree that any error occurred because we did not specifically discuss in this proposed rule whether we could or should regulate EGUs under CAA section 112(n)(1) instead of CAA section 112(d).[63] The Agency validly listed EGUs in 2000 and listed sources must be regulated pursuant to CAA section 112(d).

Even if we agreed that regulation under CAA section 112(n)(1) was a viable option for EGUs, we would still have listed and regulated EGUs like other sources because CAA section 112(d) provides a statutory framework for regulating HAP emissions from sources and CAA section 112(n)(1) does not. We believe that even if CAA section 112(n)(1) were available to regulate EGUs, there would be sufficient uncertainty about the legal vulnerability of such an approach to caution against employing it. This legal uncertainty would be particularly troubling in light of the fact that we have identified hazards to public health and the environment from HAP emissions from EGUs that warrant regulation, and these regulations are long overdue.

The commenter also takes issue with our statement in the preamble to the proposed rule that the use of the words "section", "subsection", and "subparagraph" in CAA section 112(n)(1)(A) "demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs." *See* 76 FR 24993. The commenter appears to make much of our use of the word "must" in that sentence and also states that our interpretation of the significance of the use of the three terms in CAA section 112(n)(1)(A) is flawed because Congress only used the three terms for purposes of clarity. The commenter is incorrect on both points. With respect to the commenter's concern regarding the use of the word "must" in the sentence quoted above, we note that in the next sentence we stated that "Congress directed the Agency to regulate utilities 'under this section,' and accordingly EGUs *should* be regulated in the same manner as other categories for which the statute requires regulation." Id. (*emphasis added*). We were not foreclosing the possibility of any alternative interpretation and our use of the term "must" should not detract from the point we were trying to make. Specifically, we believe that Congress would have directed us to regulate EGUs under CAA section 112(n)(1)(A) if that was its intent and, absent that mandate, the better reading of the statute is the one provided in the preamble to the proposed rule, which is that EGUs should be listed pursuant to CAA section 112(c) and subject to CAA section 112(d) emission standards.

The commenter also stated that the EPA relied on CAA section 112(c)(6) to support a conclusion that EGUs must be regulated under CAA section 112(d). The commenter takes the EPA's statements out of context. The statement in whole read:

> Furthermore, the D.C. Circuit Court has already held that section 112(n)(1) "governs how the Administrator decides whether to list EGUs" and that once listed, EGUs are subject to the requirements of CAA section 112. *New Jersey*, 517 F.3d at 583. Indeed, the D.C. Circuit Court expressly noted that "where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly," noting that "section 112(c)(6) expressly exempts EGUs from the strict deadlines imposed on other sources of certain pollutants." *Id.* Congress did not exempt EGUs from the other requirements of CAA section 112, and once listed, EPA is required to establish emission standards for EGUs consistent with the requirements set forth in CAA section 112(d), as described below. *See* 76 FR 24993.

As can be seen from this passage, the Court cited section 112(c)(6) as an example of Congress' intent regarding regulating EGUs under CAA section 112. The commenter cited the last clause of the last sentence of the paragraph quoted above without including the prefatory clause "once listed," and, without that clause, the statement is not fairly characterized. The point the EPA was making in that paragraph is that EGUs are a listed source category and listed sources must be regulated under CAA section 112(d) unless the EPA delists the source category.

Comment: One commenter stated that EPA overstates the significance of the D.C. Circuit's holding in *New Jersey* by suggesting that the decision mandates EGU regulation under CAA section 112(d) because EGUs "remain listed" under CAA section 112(c), *See New Jersey*, 517 F.3d at 582. According to the commenter, the court declined to address the lawfulness of EPA's having "listed" EGUs under CAA section 112(c), leaving that matter to be decided if and when EPA adopted standards for EGUs under CAA section 112. Nowhere in the decision did the D.C. Circuit indicate that EPA must regulate EGUs under CAA section 112(d).

According to the commenter, the EPA must consider both whether the regulation of EGUs is "appropriate and necessary" under section 112(n)(1) and address anew whether the Agency is authorized by section 112 to list EGUs under section 112(c) at all. The commenter asserts that on the face of the proposal, the EPA has not revisited the question whether the "listing" of EGUs under section 112(c) is consistent with congressional intent.

Response: The commenter's arguments are circular and it is difficult to fully determine exactly what its issue is with EPA's listing; however, it appears that the commenter believes that EPA incorrectly relied on the *New Jersey* decision to justify the listing of EGUs. The commenter also appears to argue that the Agency has never explained why it has the authority to list EGUs at all. We disagree.

As stated in the preamble to the proposed rule, CAA section 112(n)(1)(A)

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[63] We note that in our January 2004 proposed rule, we solicited comment on whether section 112(n)(1)(A) provided independent authority to regulate EGUs. We received several comments on this issue, and we rejected the concept after reviewing the comments and further considering the language of section 112(n)(1)(A) and the structure of section 112. As such, we proposed and are finalizing that once the Agency determines that it is appropriate and necessary to regulate EGUs under section 112, those sources are listed pursuant to subsection 112(c), as we did in December 2000, and the Agency must set standards for those sources pursuant to section 112(d). See section 112(c) and (d)(1) (requiring establishment of 112(d) standards for listed source categories).

requires EPA to conduct a study of HAP emissions from EGUs and regulate EGUs under CAA section 112 if we determine that regulation is appropriate and necessary, after considering the results of the study. 76 FR 24981, 24986, and 24998. The only condition precedent to regulating EGUs under CAA section 112 is a finding that such regulation is appropriate and necessary (after conducting and considering the Utility Study), and once that finding is made the Agency has the authority to list EGUs under CAA section 112(c) as the first step in the process of establishing regulations under section 112. The D.C. Circuit agrees with that interpretation of the statute as evidenced by its statement in *New Jersey* that "section 112(n)(1)(A) governs how the Administrator decides whether to list EGUs for regulation under section 112," 517 F.3d at 582, and the Court's statement directly contradicts the commenter's position.

The EPA did not rely on the *New Jersey* decision to justify the appropriate and necessary finding as the commenter suggests. We based the finding in 2000 on the extensive information available to the Agency at the time, and we confirmed the finding in the preamble to the proposed rule based on new information. The commenter had ample opportunity to comment on the appropriate and necessary finding, and it may challenge the basis of the listing (*i.e.* the appropriate and necessary finding) when EPA issues the final standards.

Comment: One commenter believes that the D.C. Circuit will condemn the final rule as a result of EPA's "misapprehension" that upon making an "appropriate and necessary" finding, the Agency is compelled by the CAA to adopt a regulatory standard for EGUs under CAA section 112(d). According to the commenter, a regulation will be invalid if the regulation "'was not based on the [agency's] own judgment'" but "'rather on the unjustified assumption that it was Congress' judgment that such [a regulation] is desirable' or required." *See Transitional Hospitals Corp.* v. *Shalala*, 222 F.3d 1019, 1029 (D.C. Cir. 2000), quoting *Prill* v. *NLRB*, 755 F.2d 941, 948 (D.C. Cir. 1985). The commenter further notes that the D.C. Circuit has held that, where an agency wrongly construes a judicial decision as compelling a particular statutory interpretation, and thereby unduly limits the scope of its own discretion, the agency's action cannot be sustained. *See, e.g., Phillips Petroleum Co.* v. *FERC*, 792 F.2d 1165, 1171 (D.C. Cir. 1986). The commenter believes the rule is bound to be rejected and that the EPA should "reconsider the legal interpretations on which it purports to base its rule."

Response: We do not agree that we have improperly interpreted the statute as limiting our discretion in the manner suggested by the commenter. The commenter makes only one specific allegation in this comment and that concerns the Agency's conclusion that it must establish CAA section 112(d) standards for EGUs in light of the *New Jersey* decision. The commenter does not explain why that conclusion is incorrect. As we state above and in the preamble to the proposed rule, because EGUs are a CAA section 112(c) listed source category, the Agency must establish CAA section 112(d) standards or delist EGUs pursuant to CAA section 112(c)(9). *See New Jersey*, 517 F.3d at 582–83 (holding that EGUs remain listed under section 112(c)); *see also* CAA section 112(c)(2) (requiring the Agency to "establish emission standards under subsection [112] (d)" for listed source categories and subcategories); 76 FR 24998–99. We concluded in the preamble to the proposed rule that we could not delist EGUs because our appropriate and necessary analysis showed that EGUs did not satisfy the CAA section 112(c)(9)(B)(i) delisting criteria. *Id.* We did not address in the preamble to the proposed rule whether EGUs satisfied the CAA section 112(c)(9)(B)(ii) criteria because EGUs failed the first prong of the delisting provisions. *Id.* We reach the same conclusion in the final rule and also address the delisting petition submitted by this commenter. Because we cannot delist EGUs, we must regulate them under CAA section 112(d). The commenter has provided no legitimate argument to rebut this conclusion. *See also* previous responses regarding regulation under section 112(n)(1)(A).

Comment: One commenter alleges that EPA impermissibly relied on CAA section 112(c)(9) to interpret "hazards to public health", and argues that the "residual risk" provisions in CAA section 112(f)(2) are more appropriate for the establishment of standards for EGUs. The commenter stated that by using CAA section 112(c)(9)(B)(i) in defining "hazards to public health", the Agency has seized on the one interpretation of the phrase that is surely contrary to congressional intent and, thus, falls outside the permissible range of its interpretative discretion. The commenter maintains that the "delisting" criteria of CAA section 112(c)(9) are simply irrelevant to the decision whether EGU HAP emissions will present any "hazards to public health" sufficient to warrant regulation of those emissions under CAA section 112.

The commenter also argues that Congress intended that EGUs be treated differently from all other "major sources" to which the "delisting" provisions of CAA section 112(c)(9), and the standard-setting provisions of CAA section 112(d) necessarily and automatically apply. Therefore, according to the commenter, the EPA's proposal to utilize the criteria of CAA section 112(c)(9) to inform its findings under CAA section 112(n)(1)(A) treats EGUs exactly the same as all other major source categories, is contrary to congressional intent, and thus unlawful. The commenter goes on to state that in exercising its discretion to define "hazards to public health" as the phrase is used in CAA section 112(n)(1)(A), the EPA would be better served to consider the "residual health risk" provisions of CAA section 112(f)(2). Those provisions provide a better analogy to the establishment of standards for EGUs under CAA section 112 than do the "delisting" criteria of CAA section 112(c)(9).

The commenter believes the category-specific criteria of paragraph (c)(9) are a poor fit for an evaluation of "hazards to public health" that should reasonably include such factors as the affected population, the characteristics of exposure, the nature of the health effects, and the uncertainties associated with the data. The commenter states that, while CAA section 112(n)(1)(A) does not expressly include any requirement that EGU emissions be regulated with an "ample margin of safety," that standard is more appropriate than the "one-in-a-million" cancer risk standard of CAA section 112(c)(9)(B)(i) that EPA proposes to employ.

Response: The commenter acknowledges that EPA has broad discretion to interpret the phrase "hazard to public health" but argues that the one thing we cannot do is use the CAA section 112(c)(9)(B) delisting provisions as a benchmark in making that interpretation. The commenter asserts that the use of the delisting standard is clearly contrary to Congressional intent but it does not provide any substantive rebuttal to our conclusion that the CAA section 112(c)(9) standards reflects the level of hazard which Congress concluded warranted continued regulation. Instead, the commenter reverted to its argument that the statute treated EGUs differently. The EPA views the disparate treatment of EGUs in a different light than commenter. While it is true that Congress established a different

statutory provision governing whether to add EGUs as a regulated source category under section 112, we do not interpret CAA section 112(n)(1)(A) as providing Congressional license to ignore risks that Congress determined warranted regulation for all other source categories. Because CAA section 112(c)(9) defines that level of risk, it is reasonable to consider it when evaluating whether EGU HAP emissions pose hazards to public health.

The commenter also suggests that the "ample margin of safety standard" of CAA section 112(f)(2) is a better fit than the one-in-a-million standard set forth in CAA section 112(c)(9)(B)(1) for evaluating hazards to public health. The commenter asserts that an evaluation of "hazards to public health" should include such factors as the affected population, the characteristics of exposure, the nature of the health effects, and the uncertainties associated with the data. However, the EPA did not rely solely on the delisting provisions for evaluating hazards to public health as commenter suggests. In fact, the EPA considered all of the factors the commenter suggests in making our finding.[64] Thus, we decline to adjust our approach to evaluating hazards to public health and the environment based on the comments.

h. 2000 Finding (and 2005 Delisting)

Comment: Several commenters generally support EPA's 2000 finding that regulating HAP emissions from EGUs under CAA section 112 is "appropriate and necessary." According to the commenters, the 2000 finding was proper under the CAA and within EPA's discretion, well-supported based on sound science available to the Agency at the time on the harm from HAP emitted by EGUs, and no additional information makes the finding invalid. Several commenters cited the conclusions of the Utility Study[65] and Mercury Study,[66] which they assert supported the finding and satisfied the only prerequisite for the finding. One commenter specifically asserted that the 2000 finding was well-supported by the Utility Study's conclusions that (1) there was a link between anthropogenic Hg emissions and MeHg found in freshwater fish, (2) Hg emissions from coal-fired utilities were expected to worsen by 2010, and (3) MeHg in fish presents a threat to public health from fish consumption. One commenter noted that the CAA does not require a conclusive link between HAP emissions and harm. One commenter stated that the CAA grants the Administrator discretion in her finding, and that discretionary decision should not be overly scrutinized, citing court opinion.[67] In support of the finding, one commenter stated that it would not make sense for Congress to limit HAP emissions from small businesses such as dry cleaners but to exempt U.S. EGUs, which are the largest sources of many HAP emissions. One commenter agreed that finding was further supported because numerous control options were available to reduce HAP emissions. One commenter agreed with the 2000 finding that the Agency lacked sufficient evidence to conclude that non-Hg HAP from EGUs posed no hazard.

The commenters who generally supported the 2000 finding also commented on specific aspects of the finding. Several commenters asserted that while the evidence on Hg alone supports the finding, the potential harm from non-Hg HAP further supported the 2000 finding. Several commenters noted that new science continues to support the 2000 finding. Several commenters also stated that the "appropriate" finding was further supported because numerous control options were available at the time of the finding that would reduce HAP emissions. One commenter concurred with EPA that regulating natural gas-fired EGUs was not appropriate and necessary because the impacts due to HAP emissions from such units are negligible based on the results of the Utility Study.

Several commenters addressed the 2005 reversal of the 2000 finding. Several commenters specifically supported the vacatur of the 2005 action. Other commenters asserted that the 2005 action was proper, and that EPA reverted back to the 2000 finding in the proposed rule without adequate explanation or support. Several commenters cited the 2005 action as invalidating the 2000 finding, specifically noting that EPA concluded that "no hazards to public health" remained after accounting for emission reductions under CAIR. These commenters assert that EPA's current position is illegal because EPA took the exact opposite position on the interpretation of the term "necessary" in its 2005 reversal, and, thus, deserves no judicial deference. One commenter stated that in 2005 EPA recognized the potential for excessive regulation created by CAA section 112 and determined that the 2000 finding lacked foundation.

Several commenters generally disagreed with the 2000 finding, with two commenters stating that EPA did not have a rational justification for it and another claiming that it was fraught with misinformation and overestimating assumptions. One commenter claimed that EPA did not explain the terms "appropriate" and "necessary" in the 2000 finding and that the emission control analysis was inadequate. Two commenters stated that the 2000 finding was based on data that was more than 10 years old, which causes serious concern regarding the validity of the findings because technology, the regulatory environment, and the economic climate have evolved. Furthermore, because the Utility Report underestimated emissions controls that EGUs would install by 2010 and additional controls that would be later required by the CSAPR, the basis for EPA's 2000 finding has changed. Several commenters stated that a "plausible link" between anthropogenic Hg and MeHg in fish is not an adequate reason for the 2000 finding. Several commenters claim that EPA only identified health concerns for Hg (and potentially Ni) but not other HAP from coal-fired EGUs in the 2000 finding, and, thus, cannot regulate HAP other than Hg because the 2000 finding authorizes only the regulation of Hg. One commenter questioned the Hg emissions underlying the 2000 finding, specifically the fraction of total deposition attributable to U.S. EGUS and the fact that EPA projected an increase in U.S. EGU emissions from 1990 to 2010 though emissions actually declined.

Several commenters raised procedural issues related to the 2000 finding. Several commenters stated that the 2000 finding failed to provide public notice and comment. According to the commenters, the CAA requires that any decision made under CAA section 112(n) must go through public notice and comment. The commenters further stated that the failure to provide public notice and comment means that this MACT is outside EPA's statutory authority. One commenter stated that because the 2000 finding was never "fully ventilated" in front of the D.C. Circuit, the EPA's authority to regulate EGUs under CAA section 112(d) is directly at issue. The commenters claim that specific issues did not undergo

[64] 76 FR 24992.

[65] U.S. EPA 1998. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress. EPA–453/R–98–004a. February.

[66] U.S. EPA, 1997.

[67] "Where a statute is precautionary in nature, the evidence difficult to come by, uncertain, or conflicting because it is on the frontiers of scientific knowledge, the regulations designed to protect the public health, and the decision that of an expert administrator, [courts] will not demand rigorous step-by-step proof of cause and effect." *Ethyl Corp. v. EPA*, 541 F.2d 1, 28 (Ct. App. D.C. Circ. 1978).

public notice and comment, including least-cost regulatory options, the impact of regulation on electricity reliability, and EPA's interpretation of the requirements under CAA section 112(n)(1)(A). One commenter claims that EPA attempted to provide after-the-fact support for its 2000 finding with new legal analysis and new factual information, contrary to *New Jersey* v. *EPA* that held that EPA may not revisit its 2000 finding except through delisting under CAA section 112(c)(9). One commenter stated that EPA's 2000 finding should be reviewed when EPA issues the actual NESHAP.[68] One commenter stated that the 2000 finding ignored EO 12866.

Response: EPA agrees with the commenters that the 2000 finding was reasonable and disagrees with the commenters asserting that the 2000 finding was unreasonable or failed to follow proper procedural requirements.

The EPA agrees that reviewing courts defer to the reasoned scientific and technical decisions of an Agency charged with implementing complex statutory provisions such as those at issue in this case. As EPA stated in the preamble to the proposed rule, the EPA maintains that the 2000 finding was reasonable and based on well-supported evidence available at the time, including the Utility Study, the Mercury Study,[69] and the NAS study,[70] which all showed the hazards to public health and the environment from HAP emitted from EGUs. New technical analyses conducted by EPA confirm that it remains appropriate and necessary to regulate HAP emissions from EGUs. Furthermore, the EPA agrees with the commenters on several points raised, specifically that EGUs were and remain the largest anthropogenic source of several HAP in the U.S., that risk assessments supporting the 2000 finding indicated potential concern for several non-Hg HAP, and that several available control options would effectively reduce HAP emissions from U.S. EGUs.

The EPA agrees with the commenters that Congress did not exempt EGUs from section 112(d) HAP emission limits while simultaneously limiting emissions at other sources with less HAP emissions. Congress simply provided EPA with a separate path for listing EGUs by requiring that the Agency evaluate HAP emissions from EGUs and determine whether regulation under CAA section 112 was appropriate and necessary. Since 1990, the EPA has promulgated regulations requiring the use of available control technology and other practices to reduce HAP emissions for more than 170 source categories. U.S. EGUs are the most significant source of HAP in the country that remains unaddressed by Congress's air toxics program. The EPA listed EGUs in 2000 because the considerable amount of available data supported the conclusion that regulation of EGUs under CAA section 112 was appropriate and necessary. That finding was valid at the time, and EPA reasonably added EGUs to the CAA section 112(c) list of sources that must be regulated under CAA section 112.

The EPA acknowledges that we did not expressly define the terms appropriate and necessary in the 2000 finding, but the finding is instructive in that it shows that EPA considered whether HAP emissions from EGUs posed a hazard to public health and the environment and whether there were control strategies available to reduce HAP emissions from EGUs when determining whether it was appropriate to regulated EGUs.[71] When concluding it was necessary, the Agency stated that imposition of the requirements of the Act would not address the identified hazards to public health or environment from HAP emissions and that section 112 was the proper authority to address HAP emissions.[72] The EPA explained in the preamble to the proposed rule its conclusion that the 2000 finding was fully supported by the information available at the time,[73] and EPA stands by the conclusions in that notice. Furthermore, the EPA provided an interpretation of the terms appropriate and necessary that is wholly consistent with the 2000 finding. The EPA does not agree with the commenters that a quantification of emissions reductions or a specific identification of the available controls was necessary to support the 2000 finding and listing. The EPA considered the Utility Study when making the finding, and that study clearly articulated the various alternative control strategies that EGUs could employ to control HAP emissions.[74] As to emission reductions, the EPA cannot estimate the level of HAP emission reductions until the Agency proposes a CAA section 112(d) standard after a source category is listed.

The EPA disagrees with commenters that suggest it was not "rational" to determine that it was appropriate to regulate HAP emissions from EGUs due to the cancer risks identified in the Utility Study or the potential concerns associated with other HAP emissions from EGUs. Nothing in CAA section 112(n)(1)(A) suggests that EPA must determine that every HAP emitted by EGUs poses a hazard to public health or the environment before EPA can find it appropriate to regulate EGUs under CAA section 112. In fact, the EPA maintains that it must find it appropriate and necessary to regulate EGUs under CAA section 112 if it determines that any one HAP emitted from EGUs poses a hazard to public health or the environment that will not be addressed through imposition of the requirements of the Act. The EPA disputes the commenters' conclusion that the 2000 finding was limited to Hg and Ni emissions, but, even if it were, the EPA reasonably concluded that EGUs should be listed pursuant to CAA section 112(c) based on the Hg and Ni finding. As stated in the 2000 finding, cancer risks from some non-Hg metal HAP (including As, Cr, Ni, and Cd) were not low enough to be to eliminate as potential concern.[75] Source categories listed for regulation under CAA section 112(c) must be regulated under CAA section 112(d), and the D.C. Circuit has stated that EPA has a "clear statutory obligation to set emission standards for each listed HAP". *See Sierra Club* v. *EPA*, 479 F.3d 875, 883 (D.C. Cir. 2007), *quoting National Lime Association* v. *EPA*, 233 F.3d 625, 634 (D.C. Cir. 2000). Therefore, even if EPA concluded that CAA section 112(n)(1) authorized a different approach for regulating HAP emissions from EGUs, the chosen course which is supported by the CAA (*i.e.*, listing under CAA section 112(c)) requires the Agency to regulate under CAA section 112(d) consistent with the statute and case law interpreting that provision.

The EPA disagrees that there is any concern regarding the validity of the 2000 finding or that the emissions information provided in the 2000 finding makes the finding "questionable" as stated by some of the commenters. The EPA maintains that the 2000 finding was sound and fully supported by the record available at the time, including the future year emissions projections. Therefore, the listing of EGUs is valid based on that finding alone. Even though Hg emissions have decreased since the 2000 finding instead of increasing as projected, the new technical analyses confirm that Hg emissions from EGUs continue to pose hazards to public

[68] *See UARG* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001).

[69] U.S. EPA, 1997.

[70] NAS, 2000.

[71] 65 FR 79830.

[72] *Id.*

[73] 65 FR 24994–24996.

[74] *See* Chapter 13 of the Utility Study (U.S. EPA, 1998).

[75] 76 FR 79827.

health and the environment. The EPA also indicated potential concern for several non-Hg HAP in the 2000 finding. It is well established that even small amounts of HAP can cause significant harm to human health and the environment.

The EPA agrees with the commenters who assert that the 2005 action was in error and disagrees with the commenters that the 2005 action invalidated the 2000 finding. As fully described in the preamble to the proposal, the EPA erred in the 2005 action by concluding that the 2000 finding lacked foundation. The 2005 action improperly conflated the "appropriate" and "necessary" analyses by addressing the "after imposition of the requirements of the Act" in the appropriate finding as well as the necessary finding. The EPA also indicated that it was not reasonable to interpret the necessary prong of the finding as a requirement to scour the CAA for alternative authorities to regulate HAP emissions from stationary sources, including EGUs, when Congress provided section 112 for that purpose. The EPA asserts that the 2000 finding was sound and fully supported by the record available at the time for all the reasons stated in this final rule and the proposed rule. The 2005 action interpreted the statute in a manner inconsistent with the 2000 finding and attempted to delist EGUs without complying with the mandates of CAA section 112(c)(9)(B). *See New Jersey*, 517 F.3d at 583 (vacating the 2005 "delisting" action). In the preamble to the proposed rule, the EPA set forth a revised interpretation of CAA section 112(n)(1) that is consistent with the statute and the 2000 finding. The EPA also explained in the preamble to the proposed rule why the 2005 action was not technically or scientifically sound. The EPA specifically addressed the errors associated with the 2005 action in the preamble to the proposed rule, and commenters' assertions do not cause us to revisit these issues. The commenter is also incorrect in suggesting that a change in interpretation is per se invalid and provided no support for that position. *See National Cable & Telecommunications Ass'n, et al.*, v. *Brand X Internet Services, et al.*, 545 U.S. 967, 981 (discussing the deference provided to an Agency changing interpretations, the Court stated "change is not invalidating, since the whole point of *Chevron* deference is to leave the discretion provided by ambiguities of a statute with the implementing Agency.") (Internal citations and quotations omitted).

The EPA disagrees with the commenters who raise concerns about the validity of the 2000 finding because the data on which that finding was based were more than 10 years old. The EPA made the finding at that time based on the scientific and technical information available, and the finding is wholly supported by that information. In addition, even though not required to do so, the EPA has since conducted new technical analyses utilizing the best information available in 2010 as several years have passed since the 2000 finding. These new analyses confirm that HAP emissions from EGUs continue to pose a hazard to public health and the environment, even after taking into account emission reductions that have occurred since 2000 from promulgated rules, settlements, and consent decrees. *See* 76 FR 24991.

Contrary to the commenter's assertion, the EPA did not violate CAA section 307(d) by not providing a notice and comment opportunity before making the December 2000 appropriate and necessary finding. One commenter challenged EPA's 2000 finding and listing on the same grounds, and the D.C. Circuit dismissed the case because CAA section 112(e)(4) clearly states that listing decisions cannot be challenged until the Agency issues final emission standards for the listed source category. *See UARG* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001). The EPA has provided the public an opportunity to comment on both the 2000 finding and the 2011 analyses that support the appropriate and necessary determination as part of the proposed rule, and anyone may challenge the listing in the D.C. Circuit in conjunction with a challenge to this final rule. The commenters could have also commented on the CAA section 112(n)(1) (*e.g.*, the Utility Study and the Mercury Study) studies in 2000 as they were included in the docket, but EPA is not aware of any comments on those studies. In any case, these studies were peer reviewed and considered the best information available at that time. The EPA has fully complied with the rulemaking requirements of CAA section 307(d).

The EPA also disagrees with the commenters' characterization of the *New Jersey* case. The D.C. Circuit did not say, as one commenter suggested, that EPA is not able to consider additional information that is collected after the 2000 finding; instead, the Court stated that EPA could not revise its appropriate and necessary finding and remove EGUs from the CAA section 112(c) list without complying with the delisting provisions of CAA section 112(c)(9). *See New Jersey*, 517 F.3d at 582–83. The EPA also disagrees with the commenter's assertion that EPA disregarded EO 12866 when making the 2000 finding. As stated in the Federal Register notice, the 2000 finding did not impose regulatory requirements or costs and was reviewed by the Office of Management and Budget (OMB) in accordance with the EO.[76]

2. New Technical Analyses

a. General Comments on New Technical Analyses

Comment: Several commenters stated that the new analyses, including the risk assessments and technology assessments, confirm that it remains appropriate and necessary to regulate U.S. EGU HAP under CAA section 112. These commenters stated that the new analyses provide even more support than the risk and technology information available at the time the 2000 finding was made, including information on further developed emissions control technology, proven and cost-effective control of acid gases using trona and dry sorbent injection, stabilized natural gas prices that makes fuel switching and switching dispatch to underutilized combined cycle plants more feasible, more information on ecosystem impacts from HAP, "hotspots" from the deposition of Hg around EGUs, the potential for re-emission of Hg, updated emissions data and future projections of HAP emissions, and modern air pollution modeling tools. One commenter states affordable control technology has been in use in this sector for 10 to 40 years, and studies on EGU-attributable Hg hazard has undergone two in-depth EPA reviews, as well as a review by the NAS. Several commenters claimed that regulating U.S. EGUs is appropriate and necessary to protect public health based on information provided in the new technical analyses. These commenters acknowledged the substantial reductions in HAP from recent regulations and new studies that confirm serious health risks from HAP exposure. One commenter stated that new studies show higher risks to fetuses than previously estimated, increasing the potential for neurodevelopmental effects in newborns. One commenter noted that EGUs are a major source of HAP, including HCl, HF, As, antimony, Cr, Ni, and selenium, all of which adversely affect human health. The commenter stated that because of these health effects, the EPA has ample evidence to support a determination

[76] 65 FR 79831.

that non-Hg HAP emissions present a risk to human health.

Other commenters disagreed that the new analyses confirm that it remains appropriate and necessary to regulate U.S. EGUs. One commenter claims that EPA tried to use the new technical analyses to provide retroactive justification for the 2000 finding, which only found "plausible links" of health effects and "potential concerns" of health effects of certain metal emissions, dioxins and acid based aerosols. The commenter also asserted that none of these new analyses demonstrate that EGU regulation under section 112 is necessary and appropriate.

One commenter agreed that EPA may supplement its finding with new information, analyses and arguments to reaffirm the 2000 finding up until EPA issues final emissions standards. The commenter noted that the CAA does not freeze the finding. However, another commenter argued that EPA does not have the authority to rely on new technical analyses because the CAA requires EPA to make the finding on the basis of the Utility Study alone. According to that commenter, the EPA unreasonably stretched the language of CAA section 112 by considering new technical analyses.

Citing a report from Dr. Willie Soon that was submitted to the SAB, one commenter stated that the new technical analyses supporting the proposed rule do not conform to the Information Quality Act, which requires that information relied on by EPA be accurate, reliable, unbiased, and presented in a complete and unbiased manner.

Response: The EPA agrees with the commenters that state that the new technical analyses (*e.g.*, the risk assessments and technology assessment) confirm the 2000 finding and disagrees with the commenters that state otherwise. The EPA also agrees with the commenters that the 2000 finding was valid at the time it was made based on the CAA section 112(n)(1) studies and other information available to the Agency at that time. Furthermore, the EPA agrees with commenters that the final rule will lead to substantial reductions in HAP emissions from EGUs, that control of the HAP is estimated to lead to public health and environmental benefits as discussed in the RIA, that Hg emissions from U.S. EGUs pose a hazard to public health, and that non-Hg HAP emissions from EGUs pose a hazard to public health.

Although these new analyses were not required, the EPA agrees with the commenters that stated that EPA is authorized to conduct additional analyses to confirm the 2000 finding. The EPA disagrees with the commenter's assertion that the Agency is not authorized to consider new information and at the same time unable to use the information available in 2000 because, according to the commenter, that information is "stale." Under this theory, the Agency could not ever make an appropriate and necessary finding prospectively, thereby excusing the Agency from its obligations to protect public health and the environment because it did not diligently act in undertaking its statutory responsibility to establish CAA section 112(d) standards within two years of listing EGUs. *See* CAA section 112(c)(5). This is an illogical result that finds no basis in the statute. The EPA also disagrees with the commenter's assertion that EPA may not consider new analyses conducted after the Utility Study in determining whether it is appropriate and necessary to regulate EGUs under section 112 for the reasons set forth in the preamble to the proposed rule.[77]

The EPA disagrees with the commenter's implication that EPA conducted the new analyses because of alleged flaws in the 2000 finding. As explained in detail in the preamble to the proposed rule, the 2000 finding was wholly valid and reasonable based on the information available to the Agency at that time, including the Utility Study. Further, the EPA maintains that had it complied with the statutory mandate to issue CAA section 112(d) standards within two years of listing EGUs, the EPA would likely have declined to conduct new analyses. The EPA conducted new analyses because over 10 years had passed since the 2000 finding, and EPA wanted to evaluate HAP emissions from U.S. EGUs based on the most accurate information available, though the Agency was not required to reevaluate the 2000 finding. In conducting the new analyses, the EPA used this updated information to further support the finding.

The EPA strongly disagrees with the commenter that stated that EPA failed to conform to the Information Quality Act. The EPA used peer reviewed information and quality-assured data in all aspects of the technical analyses used to support the appropriate and necessary finding supporting this regulation. In addition, the EPA submitted the Hg Risk TSD to the SAB for peer review, which "supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs."[78] The SAB received the comments from Dr. Willie Soon, and had those comments available for consideration in their deliberations regarding the Hg risk analysis. The SAB specifically supported elements of the analysis criticized by Dr. Willie Soon regarding the use of the EPA RfD as a benchmark for risk and the connection between Hg emissions from U.S. EGUs and MeHg concentrations in fish. In addition, the risk assessment methodology for the non-Hg case studies is consistent with the methodology that EPA uses for assessments performed for Risk and Technology Review rulemakings, which underwent peer review by the SAB in 2009.[79] During the public comment period, the EPA also completed a letter peer review of the methods used to develop inhalation cancer risk estimates for Cr and Ni compounds, and those reviews were generally supportive. See above description of this peer review. For the final rulemaking, the EPA revised both risk assessments consistent with recommendations from the peer reviewers. The EPA relies on the SAB's review of the quality of the information supporting the analytical results. Accordingly, contrary to the commenters' assertions, the EPA acted consistently with the Information Quality Act as well as EPA's and OMB's peer review requirements.

b. Hg Emissions Estimates

1. Hg Emissions From EGUs

Comment: The commenters addressed the 2005 and 2016 emissions estimates for Hg and expressed concern that inaccuracies in these emissions estimates result in overestimates of risks from Hg deposition. Further, commenters compared EPA's 2010 estimate and 2016 estimate, and stated that it is not possible for 29 tons to be a correct inventory total for Hg emissions in both years given expected reductions from CSAPR. In addition, commenters specifically commented on assumptions included in the Integrated Planning Modeling (IPM), including a concern that Hg speciation factors used by IPM overestimate emissions in 2016. Other commenters noted that EGU sources are the predominant source of U.S. anthropogenic Hg emissions, particularly the oxidized and particulate forms of Hg that are of primary concern for Hg deposition.

Response: The EPA disagrees with commenters' assertions that the EPA's

[77] 76 FR 24988.

[78] U.S. EPA–SAB, 2011.

[79] U.S. EPA–SAB, 2010.

emissions estimates overestimate risk. While EPA agrees that the 2005 Hg emissions may be overestimated, such an overestimate in 2005 would actually lead to an underestimate of risk in 2016 and not an overestimate of risk, as claimed by the commenter, because the ratio approach used by EPA to scale fish tissue data would underestimate risk if 2005 Hg estimates were overestimated. Since the 2005 emissions are not used as a starting point for 2016 emissions from IPM, any 2005 overestimate does not affect the 2016 emissions levels. The 2016 emissions are computed by IPM based on forecasts of demand, fuel type, Hg content of the fuel, and the emissions reductions resulting from each unit's configurations. *See* IPM Documentation for further information, which is available in the docket. No commenter has provided any evidence that the IPM 2016 emissions projection methodology resulted in an overestimate.

The EPA acknowledges that the current Hg emissions estimate would not be the same as the 2016 Hg emissions estimate given that compliance with CSAPR is anticipated to have some Hg co-benefits. For this reason, the EPA reflected emission reductions anticipated from CSAPR in the Hg deposition modeling for 2016 in the Hg Risk TSD. In the final rule, the EPA revised the estimate of Hg emissions remaining from U.S. EGUs in 2016, which includes additional emission reductions anticipated from the final CSAPR. The revised estimate shows that U.S. EGUs would emit 27 tons of Hg in 2016. Although EPA does not use the current Hg emissions estimates in any of the risk calculations, the EPA estimates that current Hg emissions are 29 tons. Conclusions about the trend between current emissions and emissions in 2016 are limited by the fact that different methods were used to compute the two estimates, as fully explained in the revised Emissions Overview memo in the docket.

The EPA disagrees with the commenter's assertion that incorrect Hg emission factors result in incorrect 2016 emissions. The 2016 projected Hg emissions are not based on emissions factors. The 2016 Hg emissions are computed by the IPM based on forecasts of demand, fuel type, Hg content of the fuel, and the emissions reductions resulting from each unit's configurations. The speciation factors referenced by the commenter provide a basis for the speciation of total projected Hg emissions into particulate, divalent gaseous, and elemental species, and do not impact the total amount of Hg emissions.

The EPA agrees with commenters who noted that EGU sources are the predominant source of U.S. anthropogenic Hg emissions, and in particular the oxidized and particulate forms of Hg that are of primary concern for Hg deposition.

2. Global Hg Emissions

Comment: Several commenters stated that predicted Hg deposition relies heavily on the amount of gaseous elemental Hg used to define the boundary and initial conditions of a model, e.g., the Hg that enters the U.S. from outside the U.S. boundaries. The commenters asserted that this is especially important because Hg emissions from Asia—the region immediately upwind of North America that affects U.S. Hg deposition significantly and also affects it the most compared to other regions—are expected to continue to increase.[80 81 82 83 84 85] According to the commenter, this would affect the amount of Hg in the boundary and initial conditions. The commenters claim that EPA's modeling did not account for these emission changes, thus leading to an overestimate of U.S. EGU-attributable deposition in 2016.

Several commenters noted that Hg emissions from U.S. EGUs are small when compared to global Hg emissions totals and natural sources within the U.S. These commenters used a variety of information to support alternative conclusions about the necessity to control U.S. EGU emissions to reduce Hg risk: global Hg emissions inventories, global and regional photochemical modeling research, and observation-based assessments. A commenter stated that EPA has not acknowledged the dramatic decline in Hg emissions from U.S. EGUs since the late 1990s (approximately 50 percent) to the current level or consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources, natural (such as fires) and human-caused.

Response: The EPA disagrees that boundary and initial conditions used in modeling Hg deposition need adjustment for several reasons. First, the EPA does not use the first 10 days of the modeling simulation in the analysis, which is more than sufficient to remove the influence of initial conditions on Hg deposition estimates.[86] Second, it is difficult to accurately characterize the speciation of Hg that flows into the U.S. from other countries due to the lack of data near the boundaries of the modeling domain. Third, the boundary inflow for the CMAQ Hg modeling used in the Hg deposition modeling are based on a global model GEOS–CHEM simulation using a 2000 based global inventory.[87] A recently published comparison of global Hg emissions by continent for 2000 and 2006 found that total Hg emissions from Asia (and Oceania) total 1,306 Mg/yr in 2000 and 1,317 Mg/yr in 2006.[88] The EPA has determined that because the Asian Hg emissions estimated in this study are nearly constant between 2005 and 2006, any adjustments to the boundary conditions or adjustments to modeled Hg deposition would be invalid and inappropriate. Recent research has shown that ambient Hg concentrations have been decreasing in the northern hemisphere since 2000.[89] Because emissions from Asia have not appreciably changed between 2000 and 2006 and ambient Hg concentrations have been decreasing, ENVIRON's analysis contains incorrect assumptions and we need not address them further. For these reasons and the large uncertainties surrounding projected Hg

[80] Jaffe D., Prestbo E., Swartzendruber P., Weiss-Penzias P., Kato S., Takami A., Hatakeyama S., Kajii Y., 2005. "Export of Atmospheric Mercury From Asia," *Atmospheric Environment*, 39, 3029–3038.

[81] Jaffe D., Strode S., 2008. "Fate and Transport of Atmospheric Mercury From Asia," *Environmental Chemistry*, 5, 121.

[82] Pacyna E.G., Pacyna J.M., Sundseth K., Munthe J., Kindbom K., Wilson S., Steenhuisen F., Maxson P., 2010. "Global Emission of Mercury to the Atmosphere From Anthropogenic Sources in 2005 and Projections to 2020," *Atmospheric Environment*, 44, 2487–2499.

[83] Pirrone N., Cinnirella S., Feng X., Finkelman R.B., Friedli H.R., Leaner J., Mason R., Mukherjee A.B., Stracher G.B., Streets D. G., Telmer K., 2010. "Global Mercury Emissions to the Atmosphere From Anthropogenic and Natural Sources," *Atmospheric Chemistry and Physics*, 10, 5951–5964.

[84] Streets, D.G., Zhang, Q., Wu, Y., 2009. "Projections of Global Mercury Emissions in 2050." *Environmental Science & Technology* 43, 2983–2988.

[85] Weiss-Penzias P., Jaffe D., Swartzendruber P., Dennison J.B., Chand D., Hafner W., Prestbo E., 2006. "Observations of Asian Air Pollution in the Free Troposphere at Mt. Bachelor Observatory in the Spring of 2004," *Journal of Geophysical Research*, 110, D10304.

[86] Pongprueksa, P., Lin, C.J., Lindberg, SE., Jang, C., Braverman, T., Bullock, O.R., Ho, T.C., Chu, H.W., 2008. "Scientific Uncertainties in Atmospheric Mercury Models III: Boundary and Initial Conditions, Model Grid Resolution, and Hg (II) Reduction Mechanism." *Atmospheric Environment* 42, 1828–1845.

[87] Selin, NE., Jacob, D.J., Park, R.J., Yantosca, R.M., Strode, S., Jaegle, L., Jaffe, D. 2007. "Chemical Cycling and Deposition of Atmospheric Mercury: Global Constraints From Observations." *Journal of Geophysical Research-Atmospheres* 112.

[88] Streets *et al.*, 2009.

[89] Slemr, F., Brunke, E.G., Ebinghaus, R., Kuss, J., 2011. "Worldwide Trend of Atmospheric Mercury Since 1995." *Atmospheric Chemistry and Physics* 11, 4779–4787.

global inventories, the EPA concludes that the most appropriate technical choice is to keep the Hg boundary conditions the same between the 2005 and 2016 simulations.

The EPA also disagrees with the commenters' assertion that EPA has not acknowledged the decline in Hg emissions for the U.S. EGUs since the late 1990s. The EPA analyzed historical, current, and future projected Hg emissions from the power generation sector, as cited in the preamble to the proposed rule. The EPA also disagrees with the commenters' assertions that EPA failed to consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources. As noted in the Hg Risk TSD, the EPA modeled Hg emissions from U.S. and non-U.S. anthropogenic and natural sources to estimate Hg deposition across the country. The EPA also determined the contribution of Hg emissions from U.S. EGUs to total Hg deposition in the U.S. by running modeling simulations for 2005 and 2016 with Hg emissions from U.S. EGUs set to zero. Based on the Hg Risk TSD, Hg emissions from U.S. EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition.

The commenters suggest that Hg emissions from U.S. EGUs represent a limited portion of the total Hg emitted worldwide, including anthropogenic and natural sources. While EPA acknowledges that Hg emissions from U.S. EGUs are a small fraction of the total Hg emitted globally, it views the environmental significance of Hg emissions from U.S. EGUs and other domestic sources as a more germane consideration. Mercury is emitted from EGUs in three forms. Each form of Hg has specific physical and chemical properties that determine how far it travels in the atmosphere before depositing to the landscape. Although gaseous oxidized Hg and particle-bound Hg are generally local/regional Hg deposition concerns, all forms of Hg may deposit to local or regional watersheds. U.S. coal-fired power plants account for over half of the U.S. controllable emissions of the quickly depositing forms of Hg. Although emissions from international Hg sources contribute to Hg deposition in the U.S., the peer reviewed scientific literature shows that Hg emissions from U.S. EGUs in the U.S. significantly enhance Hg deposition and the response of ecosystems in the U.S. [90] [91] [92] [93]

c. Hg Deposition Modeling

1. General Comments on Deposition Modeling

Comment: Several commenters stated that according to the ENVIRON report, the EPA overestimated U.S. EGU-attributable Hg deposition by 10 percent on average (and up to 41 percent in some areas). The commenters claim this overestimation is the result of boundary condition treatment, the exclusion of U.S. fire emissions,[94] and Hg plume chemistry approach. In addition, one commenter referenced the same ENVIRON report and stated that before implementation of controls required by the proposed rule, areas with relatively high EGU-attributable Hg deposition (one-fifth or more of total deposition) in 2016 constitute less than 0.25 percent of the continental U.S. area, and only three grid cells have EGU contributions exceeding half of total deposition.

Another commenter suggested that current research shows that models of Hg atmospheric fate and transport overestimate the local and regional impacts of some anthropogenic sources, such as U.S. EGUs. Thus, according to the commenter, calculated contributions to Hg deposition and fish tissue MeHg levels from these sources represent upper bounds of actual contributions,[95] [96] and EPA should present results as estimates of lower and upper bound limits.

Response: The EPA disagrees with the information presented by ENVIRON. The ENVIRON report is based on the misapplication of multiple incommensurate modeling studies and false premises which include the incorrect notion that the boundary conditions are over-estimated and the idea that EPA should use in-plume chemistry that has not been explicitly characterized and peer reviewed. Reactions that may reduce gas phase oxidized Hg in plumes have not been explicitly identified in literature. Recent studies in central Wisconsin and central California suggest the opposite may happen; elemental Hg may be oxidized to Hg(II) in plumes.[97] [98] Better field study measurements and specific reaction mechanisms need to be identified before making conclusions about potential Hg in-plume chemistry or applying surrogate reactions in regulatory modeling. The possibility that Hg(0) is oxidized to Hg(II) in plumes suggests coal-fired power plant Hg contribution inside the U.S. may be underestimated in EPA modeling.

The EPA asserts that the numbers suggested by the commenter are inaccurate, as it is not appropriate to adjust EPA's deposition estimates based on previous Hg modeling done with older Hg chemistry, in-plume reactions that have not been explicitly identified, and erroneous adjustments to Hg boundary inflow. Recent research has shown that ambient Hg concentrations have been decreasing in the northern hemisphere since 2000.[99] The EPA declines to revise this analysis as commenter suggests for several reasons, including available evidence indicates that emissions from China have not appreciably changed between 2000 and 2006 [100] and ambient Hg concentrations have decreased, the commenter inappropriately comingled out-of-date Hg modeling simulations with EPA results, and ENVIRON's analysis has not undergone any scientific peer review and presents information with incorrect assumptions as noted in this response.

The EPA also disagrees with the commenter's interpretation of the applicability of wildfire Hg emissions to

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[90] Caffrey *et al.*, 2010.

[91] Driscoll, C. T., Han, Y.-J., Chen, C. Y., Evers, D. C., Lambert, K. F., Holsen, T. M., *et al.*, (2007). "Mercury Contamination in Forest and Freshwater Ecosystems in the Northeastern United States." *BioScience*, 57(1).

[92] Keeler, G.J., Landis, M.S., Norris, G.A., Christianson, E.M., Dvonch, J.T., 2006. "Sources of Mercury Wet Deposition in Eastern Ohio, USA." *Environmental Science & Technology* 40, 5874–5881.

[93] White, E.M., Keeler, G.J., Landis, M.S., 2009. "Spatial Variability of Mercury Wet Deposition in Eastern Ohio: Summertime Meteorological Case Study Analysis of Local Source Influences." *Environmental Science & Technology* 43, 4946–4953.

[94] Finley, B.D., Swartzendruber, P.C., Jaffe, D.A., 2009. "Particulate Mercury Emissions in Regional Wildfire Plumes Observed at the Mount Bachelor Observatory." *Atmospheric Environment* 43, 6074–6083.

[95] Seigneur, C., Lohman, K., Vijayaraghavan, K., Shia, R.L., 2003. "Contributions of global and regional sources to mercury deposition in New York State." Environmental Pollution 123, 365–373.

[96] Seigneur, C., Vijayaraghavan, K., Lohman, K., Karamchandani, P., Scott, C., 2004. "Modeling the atmospheric fate and transport of mercury over North America: power plant emission scenarios." *Fuel Processing Technology* 85, 441–450.

[97] Kolker, A., Olson, M.L., Krabbenhoft, D.P., Tate, M.T., Engle, M.A., 2010. "Patterns of mercury dispersion from local and regional emission sources, rural Central Wisconsin, USA." *Atmospheric Chemistry and Physics* 10, 4467–4476.

[98] Rothenberg, SE., McKee, L., Gilbreath, A., Yee, D., Connor, M., Fu, X.W., 2010. "Wet deposition of mercury within the vicinity of a cement plant before and during cement plant maintenance." *Atmospheric Environment* 44, 1255–1262.

[99] Slemr *et al.*, 2011.

[100] Streets *et al.*, 2009.

[101] Finley *et al.*, 2009.

this assessment. Finley *et al.*, (2009) [101] suggests caution when using their field data to make assumptions about Hg(p) emissions from wildfires; the estimated particulate Hg emissions from wildfires is based on one field site with a limited sample size, and the assumptions made (such as the observed Hg(p) to carbon monoxide ratios at this location) may not be valid on a broader scale.[102] Mercury emissions from wildfires are a re-volatilization of previously deposited Hg.[103] Given that electrical generating power plants are currently and historically have been among the largest Hg-emitting sources, the inclusion of wildfire emissions in a modeling assessment would necessarily increase the contribution from this emissions sector.

The EPA disagrees with the assertion that EPA failed to consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources and disagrees with the interpretation of EGU deposition presented in the ENVIRON report. As noted in the Hg Risk TSD, the EPA modeled Hg emissions from U.S. and non-U.S. anthropogenic and natural sources to estimate Hg deposition across the country. The EPA also determined the contribution of Hg emissions from U.S. EGUs to total Hg deposition in the U.S. by running modeling simulations for 2005 and 2016 with Hg emissions from U.S. EGUs set to zero. Hg emissions from U.S. EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. The ENVIRON report provides no risk analysis of EGU contribution.

The EPA disagrees that research [104] [105] presented by the commenter shows that U.S. EGU impacts are over-estimated. The commenter's references do not support this statement. The references provided by the commenter are based on Hg modeling that uses models that are no longer applied and that are based on out-dated Hg chemistry and deposition assumptions. Given the advances in Hg modeling since the early 2000s, the EPA does not believe an upper and lower bound estimate is necessary.

[100] Streets *et al.*, 2009.

[101] Finley *et al.*, 2009.

[102] *Id.*

2. Chemical Reactions

Comment: Several commenters stated that the CMAQ modeling fails to account for the chemical reduction of gaseous ionic Hg to elemental Hg that may occur in EGU plumes. The commenters noted that EPA did not use the Electric Power Research Institute's (EPRI) Advanced Plume-in-Grid Treatment, which includes a surrogate reaction to reduce gaseous ionic Hg to elemental Hg inside plumes. Multiple commenters claimed that the reduction of reactive gaseous Hg to gaseous elemental Hg has been reported in power plant plumes and that supporting data include atmospheric concentrations of speciated Hg measured downwind of power plant stacks at ground-level monitor sites and dispersion model predictions.[106] [107] A detailed description of various plume measurement studies is provided in EPRI Comments, Section 3.4: Plant Bowen, Georgia, Plant Pleasant, Wisconsin, and Plant Crist, Florida. One commenter believed the impact of grid resolution (12 km sized grid cells) on the CMAQ modeling was not appropriately addressed by EPA. Their concerns due to grid resolution include the notion that a source's emissions will be averaged over the entire grid cell. According to the commenter, such averaging causes an artificially fast dilution that smoothes out areas of high and low deposition, which may limit the ability of the model to simulate smaller areas of localized high deposition. This commenter believed that using the APT would address these issues.

Response: The EPA disagrees with the commenters' claims that oxidized Hg chemically reduces to elemental mercury within the plume. There is no evidence of these chemical reactions in the scientific literature. The references cited by the commenters are from non-peer reviewed reports and conference proceedings. The EPA does not consider information presented at conferences or industry reports to be peer reviewed literature, and consideration of oral presentation material would be inappropriate. Further, even these cited references do not provide sufficient information for incorporating the supposed reactions into the modeling (*e.g.*, specific chemical reactions, reaction rates, etc.); rather, the cited references only suggest that oxidized gas phase Hg could be reduced and postulate a possible pathway.

Recent studies in central Wisconsin and central California suggest the opposite may happen; elemental Hg may be oxidized to Hg(II) in plumes.[108] [109] Better field study measurements and specific reaction mechanisms need to be identified before making conclusions about potential Hg in-plume chemistry or applying surrogate reactions in regulatory modeling. Currently, models such as Advanced Plume Treatment (APT) use a surrogate reaction for the potential reactive gas phase Hg reduction that may or may not occur in plumes.[110] Reactions that may reduce gas phase oxidized Hg in plumes have not been explicitly identified in literature. The application of potentially erroneous in-plume chemistry that is a fundamental component of APT would be inappropriate. In addition, the APT is not available in the most recent version of CMAQ. It would be inappropriate for EPA to apply an out of date photochemical model with in-plume chemistry that has not been shown to exist.

The EPA agrees with the commenter that the CMAQ modeling with 12 km grid resolution may provide a lower bound estimate on EGU contribution as higher impacts using finer grid resolution are possible. The commenter's assertion that EGU impacts are likely higher further supports the final conclusions of the exposure modeling assessment. The EPA notes that the application of a photochemical model at a 12 km grid resolution for the entire continental U.S. is more robust in terms of grid resolution and scale that anything published in literature and represents the most advanced modeling platform used for a national Hg deposition assessment.

3. Modeled Deposition Compared to Measured Deposition

Comment: Multiple commenters expressed dissatisfaction related to EPA's model performance evaluation of CMAQ estimated Hg deposition. The commenters stated that EPA failed to evaluate the CMAQ model against real-world measurements and that EPA fails to provide first-hand information on wet and dry deposition processes. The commenters also stated that EPA needs

[103] Wiedinmyer, C., Friedli, H., 2007. "Mercury emission estimates from fires: An initial inventory for the United States." *Environmental Science & Technology* 41, 8092–8098.

[104] Seigneur *et al.*, 2003.

[105] Seigneur *et al.*, 2004.

[108] Kolker *et al.*, 2010.

[109] Rothenberg *et al.*, 2010.

[110] Vijayaraghavan, K., Seigneur, C., Karamchandani, P., Chen, S.Y., 2007. "Development and application of a multipollutant model for atmospheric mercury deposition." *Journal of Applied Meteorology and Climatology* 46, 1341–1353.

to assess how predicted values of deposition compare to Mercury Deposition Network (MDN) data and how predicted values of ambient speciated Hg concentrations compare to measurement networks like AMNet and SEARCH. In addition, commenters stated that EPA used highly aggregated performance metrics comparing model estimates to observations that they believe result in a degraded and lenient operational evaluation of the modeling system. A commenter suggested that EPA's model performance provides no confidence for the intended purpose of estimating deposition near point sources. One commenter simply noted that EPA's model over-estimated total Hg wet deposition at MDN monitors. Finally, several commenters noted that EPA presented a negative modeled wet deposition total in the Air Quality Modeling TSD, which is physically impossible.

Response: EPA agrees with the commenters that the negative estimate for wet deposition in the Air Quality Modeling TSD was an error. This error reflected an incorrect calculation in the post-processing of model and observation pairs that only influenced the calculation of model performance metrics. The error has been fixed, and the model performance metrics in the revised Air Quality Modeling TSD have been updated. This error did not affect Hg deposition. In response to comments, the EPA provided additional model performance evaluation by season to the revised Air Quality Modeling TSD. In addition, in response to comments, the EPA also included model performance evaluation for total Hg wet deposition for the 36 km modeling domain in the revised Air Quality Modeling TSD.

The EPA disagrees that it did not conduct an assessment comparing CMAQ total Hg wet deposition estimates to MDN data. The Air Quality Modeling TSD clearly shows a comparison of CMAQ estimated total Hg wet deposition with MDN data for the entire length of the modeling period. The CMAQ wet deposition of Hg has been and will continue to be extensively evaluated against MDN sites.[111] There is no dry deposition monitoring network, which precludes evaluating CMAQ dry deposition processes. The EPA disagrees that an evaluation of ambient speciated Hg against routine monitor networks such as AMNet or SEARCH would be useful for this particular modeling application. The AMNet Hg network did not exist in 2005, which is EPA's baseline model simulation time period, and the SEARCH network started making preliminary measurements of Hg at one or two sites in 2005. In addition, measurement artifacts related to gaseous oxidized Hg are difficult to quantify and make direct comparison to model estimates problematic.[112] Considering the problems associated with TEKRAN measurements of ambient Hg and the sparse nature of routine measurements in the U.S., the EPA did not compare ambient Hg against model estimates.

The EPA disagrees that the model performance presented in the air quality TSD is insufficient. The EPA asserts that the model performance evaluation is generally similar to the level of model performance presented in literature. One commenter presented the results of several Hg modeling studies as providing information that the commenter believes to be relevant for this assessment in terms of model performance metric estimation and the level of model performance evaluation shown for assessments modeling Hg near point sources. For example, one cited study titled "Modeling Mercury in Power Plant Plumes" models near-source Hg chemistry from U.S. EGUs, but provides absolutely no information about model performance evaluation.[113]

Another commenter identified two studies as supposedly having Hg modeling results that are applicable to EPA's analysis.[114] [115] These studies present similar model performance metrics as EPA. The EPA disagrees that the Agency used "highly aggregated performance metrics" that result in degraded and lenient model evaluation. The studies presented [116] [117] as relevant for point source mercury modeling use an approach to aggregate the operational performance metrics across many monitor locations as did EPA; however, these articles calculate long term annual averages of modeled and observed total Hg wet deposition before estimating performance metrics. It is common practice to pair modeled estimates and observations in space and time (weekly in this case) and estimate performance metrics, then average all the metrics together. The latter is the approach taken by the EPA and should have been taken by the studies presented by the commenter. The EPA used a more stringent approach to match observations and predictions and aggregation of operational model performance. The EPA agrees that the commenter accurately restated total wet deposition model performance information provided by the EPA in the Air Quality Modeling TSD. To provide context, other Hg modeling studies show a positive bias for annual total Hg wet deposition.[118] [119] An annual Hg modeling application done by ENVIRON [120] and the Atmospheric and Environmental Research for Lake Michigan Air Directors Consortium show seasonal average normalized bias between 70 and 158 percent and seasonal average normalized error between 72 and 503 percent.[121] These results indicate a very large over-estimation tendency. The model performance shown by EPA is consistent with other long-term Hg modeling applications.

4. Excess Local Deposition From Hg Emissions From U.S. EGUs (Deposition Hotspots)

Comment: One commenter stated that reducing Hg will benefit local environments. The commenter stated that a 2007 study confirmed the presence of Hg "hotspots" downwind from coal-fired power plants and confirmed that coal-fired power plants within the U.S. are the primary source of Hg to the Great Lakes and the Chesapeake Bay.[122] The commenter also stated that the study is consistent with a major Hg deposition study conducted

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[111] Bullock, O.R., Atkinson, D., Braverman, T., Civerolo, K., Dastoor, A., Davignon, D., Ku, J.Y., Lohman, K., Myers, T.C., Park, R.J., Seigneur, C., Selin, NE., Sistla, G., Vijayaraghavan, K., 2009. "An analysis of simulated wet deposition of mercury from the North American Mercury Model Intercomparison Study." *Journal of Geophysical Research-Atmospheres* 114.

[112] Lyman, S.N., Jaffe, D.A., Gustin, M.S., 2010. "Release of mercury halides from KCl denuders in the presence of ozone." *Atmospheric Chemistry and Physics* 10, 8197–8204.

[113] Lohman *et al.*, 2006.

[114] Seigneur, C., Lohman, K., Vijayaraghavan, K., Jansen, J., Levin, L., 2006. "Modeling atmospheric mercury deposition in the vicinity of power plants." *Journal of the Air & Waste Management Association* 56, 743–751.

[115] Vijayaraghavan, K., Karamchandani, P., Seigneur, C., Balmori, R., Chen, S.–Y., 2008. "Plume-in-grid modeling of atmospheric mercury." *Journal of Geophysical Research-Atmospheres* 113.

[116] Seigneur, C., Lohman, K., Vijayaraghavan, K., Jansen, J., Levin, L., 2006. "Modeling atmospheric mercury deposition in the vicinity of power plants." *Journal of the Air & Waste Management Association* 56, 743–751.

[117] Vijayaraghavan, K., Karamchandani, P., Seigneur, C., Balmori, R., Chen, S.-Y., 2008. "Plume-in-grid modeling of atmospheric mercury." *Journal of Geophysical Research-Atmospheres* 113.

[118] *Id.*

[119] Vijayaraghavan *et al.*, 2007.

[120] Yarwood, G, Lau, S., Jia, Y., Karamchandani, P., Vijayaraghavan, K. 2003. Final *Report: Modeling Atmospheric Mercury Chemistry and Deposition with CAMx for a 2002 Annual Simulation.* Prepared for Wisconsin Department of Natural Resources. *http://www.gypsymoth.wi.gov/air/toxics/mercury/hg_X97579601_appB.pdf.*

[121] Yarwood *et al.*, 2003.

[122] Evers, David C. *et al.*, 2007. "Biological Mercury Hotspots in the Northeastern United States and Southeastern Canada," *Bioscience.* Vol. 57 No. 1. p. 29.

by the EPA and the University of Michigan that concluded that approximately 70 percent of Hg wet deposition resulted from local fossil fuel emissions in the region.[123]

One commenter agreed with the Agency's assessment of the potential for deposition "hotspots" that shows that Hg deposition near EGUs can be three times as large as the regional average. The commenter stated that this excess Hg deposition would substantially increase the health and environmental risks associated with emissions at these sites. The same commenter also stated that EPA applied a conservative methodology to quantify near-source Hg deposition. The commenter stated that maximum excess local Hg deposition may be significantly underestimated by averaging high deposition sites downwind of an EGU in the direction of prevailing winds with lower excess deposition at locations close to but frequently upwind of the facility. The same commenter suggests that had EPA used CMAQ and individual 12x12 km^2 grid cells to quantify local deposition, the model could increase the excess Hg deposition at these locations significantly and place them at even greater risk of adverse health and environmental effects of HAP from U.S. EGUs.

One commenter stated that the Hubbard Brook Research Foundation issued a report in 2007 that identified five Hg hotspots, one of which was in the Adirondack Park, along with four suspected hotspots.[124] The commenter stated that this study also provides a good description of the impacts of Hg on the Common Loon, which is a symbol of a healthy Adirondack environment.

One commenter stated that there is there is no evidence of Hg hotspots due to local deposition associated with coal-fired power plants. According to the commenter, the EPA's use of a 50 km radius to calculate hotspots is flawed. The commenter stated that modeling studies show that deposition of Hg emitted from power plants is not confined to a 50-km radius around the plants and that most emissions from power plants travel beyond 50 km.[125]

Several commenters stated that the EPA does not adequately define hotspots in this proposed rule. Those same commenters cited a previous EPA definition of hotspots as "a waterbody that is a source of consumable fish with MeHg tissue concentrations, attributable solely to utilities, greater than EPA's MeHg water quality criterion of 0.3 mg/kg" (milligrams per kilogram).[126] The same commenters stated that it is unclear why EPA changed from defining a hotspot by fish tissue MeHg concentration to defining a hotspot by depositional excess. Two commenters suggested that a Hg hotspot is a specific location that is characterized by elevated concentrations of Hg exceeding a well-established criterion, such as a reference concentration (RfC) when compared to its surroundings. Those same commenters stated that identifying Hg hotspots should not be constrained to locations where concentrations can be attributed to a single source or sector.[127] One of those two commenters noted that others have defined "hotspots as a spatially large region in which environmental concentrations far exceed expected values, with such values (i.e. concentrations) being 2 to three standard deviations above the relevant mean."[128]

One commenter stated that Hg concentrations are not always highest at sites closest to a major source. The commenter referred to a study[129] that demonstrated that concentrations of atmospheric reactive gaseous Hg, gaseous elemental Hg, and fine particulate Hg were lower when measured 25 km from a 1,114 MW coal-fired EGU than when measured 100 km away. The commenter stated that these findings contradict the idea, implicit in EPA's hotspot analysis, that reactive gaseous Hg decreases with distance from a large point source.

One commenter provided information from a non-peer reviewed report with wet Hg deposition measurements downwind from the coal-fired power plant Crist in Pensacola, FL. The commenter stated that using the same data from these same wet deposition sites, one study[130] found that Hg wet deposition and concentrations did not differ in a statistically significant manner among these three sites and that the concentrations values were similar to those from Mercury Deposition Network (MDN) sites that are more than 50 km away from Plant Crist located along the Northern Gulf of Mexico coast.

Another commenter stated that Plant Crist installed a wet scrubber and has operated that scrubber continuously since December 2009. The commenter stated that the scrubber reduces total Hg emissions by about 70 percent and reduces emissions of reactive gaseous Hg by about 85 percent. The commenter cited a non-peer reviewed conference presentation[131] that reported changes in Hg wet deposition relative to historic measurements. The commenter stated that, taken collectively, these findings show that increased local total Hg deposition, possibly due to EGUs, and deposition changes due to changes in EGU emissions, are small.

Two commenters stated that a study by the Department of Energy (DOE) that collected and analyzed soil and vegetation samples for Hg near three U.S. coal-fired power plants—one in North Dakota, one in Illinois, and one in Texas—found no strong evidence of "hotspots" around these three plants.

Two commenters stated that analysis of long-term trends in Hg emissions from coal-fired EGUs and wet deposition in Florida concluded that statistical analysis does not show evidence of a significant relationship between temporal trends in Hg emissions from coal-fired EGUs in Florida and Hg concentrations in precipitation during 1998 to 2010.

Two commenters stated that the Hg Risk TSD presents no information, summary statistics, and/or actual calculations showing how excess deposition within 50 km of an EGU source is obtained. The commenters stated that by assessing only Hg deposition attributable to EGUs, the EPA fails to provide a context for all other sources of Hg deposition. The commenters stated that the Agency does not explain why deposition from the top 10 percent of EGU Hg emitters does not decline, despite substantial reductions in modeled Hg emissions from those sources between 2005 and 2016.

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[123] Cohen, *et al.*, 2004. "Modeling the Atmospheric Transport and Deposition of Mercury to the Great Lakes," *Environmental Research 95*, (247–265).

[124] Driscoll, C.T., D. Evers, K.F. Lambert, N. Kamman, T. Holsen, Y-J. Han, C. Chen, W. Goodale, T. Butler, T. Clair, and R. Munson. Mercury Matters: Linking Mercury Science with Public Policy inthe Northeastern United States. 2007. Hubbard Brook Research Foundation. Science Links Publication. Vol. 1, no. 3.

[125] Seigneur *et al.*, 2006.

[126] U.S. EPA, 2005. 40 CFR Part 63 [OAR–2002–0056; FRL–7887–7] RIN 2060–AM96. *Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c).* Final rule, March 29.

[127] Evers *et al.*, 2007.

[128] Sullivan T., 2005. "The Impacts of Mercury Emissions from coal-fired Power Plants on Local Deposition and Human Health Risk." Presented at the Pennsylvania Mercury Rule Workgroup Meeting, October 28.

[129] Kolker, *et al.*, 2010.

[130] Caffrey, J.M., Landing, W.M., Nolek, S.D., Gosnell, K.J., Bagui, S.S., Bagui, S.C., 2010. "Atmospheric deposition of mercury and major ions to the Pensacola (Florida) watershed: spatial, seasonal, and inter-annual variability." *Atmospheric Chemistry and Physics* 10, 5425–5434.

[131] Krishnamurthy N., Landing W.M, Caffrey J.M., 2011. "Rainfall Deposition of Mercury and Other Trace Elements to the Northern Gulf of Mexico." Presented at the 10th International Conference on Mercury as a Global Pollutant, Halifax, Nova Scotia, Canada, July 27.

According to the commenters this implies that the top 10 percent EGUs may have approximately as much of a regional effect as a local effect.

Two commenters stated that the CMAQ model has limitations when used to predict local deposition and tends to overestimate local deposition. The commenters stated that modeling studies using either a plume model or an Eulerian model predict that 91 to 96 percent of the Hg emitted by an EGU travels beyond 50 km.[132]

Response: The EPA agrees with the commenters that stated that Hg emissions from EGUs deposit locally and regionally and contribute to excess local deposition near U.S. EGUs. The EPA acknowledges additional studies[133] cited by those commenters that corroborate EPA's conclusions. However, the EPA disagrees with those commenters' characterization of the methodology used to calculate the potential for excess local deposition. In response, the EPA has clarified the methodology in the new TSD entitled "Technical Support Document: Potential for Excess Local Deposition of U.S. EGU Attributable Mercury in Areas near U.S. EGUs," which is available in the docket.

The EPA agrees that there is no generally agreed-upon definition of "hotspot." As discussed in the preamble and TSD, for the purposes of the appropriate and necessary finding, the EPA determined that information on the potential for excess deposition of Hg in areas surrounding power plants would be useful in informing the finding. The EPA disagrees with some commenters who misinterpreted the intent of the Hg deposition hotspot analysis. Specifically, the analysis is not of "Hg hotspots", which are often defined as high Hg concentration in fish, but rather of Hg deposition hotspots, defined as excess local Hg deposition around U.S. EGUs, as clarified in the new Local Deposition TSD. Because EPA did not identify "Hg hotspots" of high Hg concentrations in fish, the EPA's MeHg water quality criterion of 0.3 mg/kg is irrelevant to EPA's analysis of excess local Hg deposition for this rule.

The EPA disagrees that the analysis assumes that deposition of Hg is confined to a 50-km radius around power plants. The purpose of the EPA's analysis was to evaluate whether there existed "excess deposition of Hg in nearby locations within 50 km of EGUs that might result in Hg deposition 'hotspots'." As explained further in the new TSD, the EPA calculated the average EGU-attributable deposition (based on CMAQ modeling of Hg deposition) in the area 500 km around each plant and the average EGU-attributable deposition in the area 50 km around each plant. The difference between those two values is the excess local deposition around the plant. The EPA does not suggest Hg emissions from power plants stop at 50 km from the source. Some portion of EGU emissions deposit before 50 km, and some portion travels beyond 50 km. In addition, Hg disperses as it transports, so the average EGU contribution can be lower in areas beyond 50km relative to areas within 50km even though Hg emissions from EGUs are depositing into U.S. watersheds.

The EPA disagrees with some commenters' interpretation of the analysis as being focused on local deposition from all sources. In fact, the focus was on excess local deposition, rather than all local deposition. The EPA has clarified the purpose of the excess local deposition analysis in the new TSD. The EPA agrees that all EGUs add to local deposition, however, not all EGUs have local deposition that greatly exceeds regional deposition, which is the relevant question. The EPA disagrees that the DOE study referenced by the commenters attempted to assess the same analytical question as EPA's analysis. The DOE study focused on comparisons of total deposition near and far from power plants. The EPA's analysis did not focus on total Hg deposition, because as EPA acknowledges throughout its analysis, global sources of Hg deposition account for a large percentage of total Hg deposition. In addition, including global sources of Hg deposition would obscure the comparison of local and regional U.S. EGU-attributable Hg deposition. Because of regional deposition from both domestic and global sources of Hg, total Hg deposition at any location is unlikely to be highly correlated with local sources. The EPA's analysis focused on U.S. EGU-attributable Hg deposition and demonstrates that for some plants (especially those with high Hg emissions), there is local deposition of Hg that exceeds the average regional deposition around the plant.

The EPA's analysis shows heterogeneity in the amount of excess local deposition around plants. The new Local Deposition TSD shows that some plants can have local deposition that is less than the regional average deposition, suggesting that most of the Hg from those plants is transported regionally or that other EGUs in the vicinity of those plants dominate the deposition of Hg near the plants. This does not detract from the overall finding that around some power plants with high levels of Hg emissions excess local deposition is on average three times the regional EGU-attributable deposition around those plants.

The EPA disagrees that the Hg Risk TSD did not provide sufficient information regarding the excess local deposition calculation. Nonetheless, the EPA has further clarified the methodology in the new Local Deposition TSD, including further descriptions of the method used to calculate the local and regional deposition around power plants along with maps and tables of results.

The EPA disagrees with the commenters that stated that the discussion of local deposition in the Hg Risk TSD did not demonstrate that Hg deposition from the top 10 percent of EGU Hg emitters declines. Table 1 of the new Local Deposition TSD clearly shows that mean local deposition (within 50km of a plant) for the top 10 percent of emitters declines from 4.89 micrograms per cubic meter ($\mu g/m^3$) to 1.18 $\mu g/m^3$. What does not change is the percent local excess for EGU-attributable Hg deposition. This implies that while Hg deposition from EGUs is declining, there is still an excess contribution to local deposition relative to regional deposition; *e.g.*, because of dispersion, the contribution to average deposition outside 50 km from the plant is lower than the contribution to average deposition within 50 km of the plant.

The EPA disagrees that the information[134] provided by the commenter regarding the Crist plant and other coal-fired power plants in Florida is relevant to EPA's analysis of excess local deposition from U.S. EGUs because it is based on measurements of wet Hg deposition without consideration of dry Hg deposition, which can be a significant component of Hg deposition.

The EPA disagrees with the commenter regarding the interpretation of the literature related to the spatial extent of deposition of Hg emitted by U.S. EGUs. The EPA also disagrees that the peer-reviewed CMAQ model has limitations for this application or overestimates local deposition. The commenter does not provide any credible support for the assertion that grid-based models typically overestimate local deposition surrounding EGUs. The EPA maintains that the CMAQ photochemical model represents the best science currently available in simulating atmospheric

[132] Edgerton *et al.*, 2006.

[133] Driscoll *et al.*, 2007.

[134] EPRI, 2010.

chemistry, transport, and deposition processes.

The study[135] cited by the commenter to support the notion that 91 to 96 percent of Hg emitted from power plants travels beyond 50 km is based on a photochemical transport model (the TEAM model) that does not employ current state-of-the-science and is not actively developed or updated. Furthermore, the modeling is based on grid cells that are 20 km in size, which limits generalizability to EPA modeling performed at 12 km grid resolution using a state of the science photochemical grid model. The cited modeling study ignores dry deposition of elemental Hg from all sources, an assumption that clearly limits the regional impacts from sources.[136] The methodology of this study cited by the commenter is critically flawed in that it presents no results where individual Hg emission sources are removed and the difference between the zero out simulation (where emissions from U.S. EGUs are set to zero) and the baseline model simulations are directly compared. Finally, the modeling study cited by the commenter presents an illustration of gridded total annual Hg deposition from the TEAM model for the eastern U.S. that clearly shows elevated annual total Hg deposition in the vicinity of coal-fired power plants in the Ohio River Valley and northeast Texas.

d. Hg Risk TSD

1. Assumption of Linear Proportionality in Relationship Between Changes in Hg Deposition and Changes in Fish Tissue Hg Concentrations (Mercury Maps)

Comment: Several commenters criticized EPA's assumption that changes in deposition resulting from U.S. EGU emissions of Hg will result in proportional changes in fish tissue Hg concentrations at the watershed level, as supported by the Mercury Maps modeling exercise. According to one commenter, the Mercury Maps model has limited capability to adequately determine bioaccumulation in fish. The same commenter stated that the Mercury Cycling Model (MCM) developed by EPRI is a more rigorous model that was developed expressly to evaluate the relationship between changes in atmospheric Hg deposition to waterbodies and changes in fish tissue MeHg levels.

Several commenters stated that the Mercury Maps model has many deficiencies. Those commenters stated that Mercury Maps is a static model unable to account for the dynamics of ecosystems that affect Hg bioaccumulation in fish, cannot consider non-air Hg inputs to watersheds, and assumes reductions in airborne Hg lead to proportional reductions in fish MeHg concentrations. Another commenter claimed that data that demonstrate a steady-state linear reduction in fish tissue MeHg in response to a reduction in atmospheric Hg deposition within watersheds do not exist and provided several references that they claimed show non-linear responses to changes in Hg deposition.[137] [138]

The same commenter disagreed with EPA's interpretation of Figure 2–17 in the March TSD and stated that a U.S. Geological Survey national waterway study[139] showed that sheet flow and drainage, not deposition, dominated input to the waterbodies it surveyed. The commenter stated that sheet flow and drainage could contain Hg and thus complicate the relationship that EPA asserts is linear and direct. Another commenter cited Figure 2–17 in the Hg Risk TSD as showing that there is no well-defined relationship between Hg deposition and MeHg concentrations in fish tissue on a national basis.

Several commenters provided comments related to the assumption that fish tissue Hg levels used in the analysis represent a steady-state. One commenter stated that given the demonstrated lag time in response to deposition change, it is logical to conclude that a lag time needs to be incorporated in Mercury Maps to adjust the estimation of how much fish tissue MeHg levels decrease in response to decreases in Hg deposition attributable to U.S. EGUs. According to the same commenter, the METAALICUS study shows that there is a lag time (and a non-proportional response) after 3–4 years. The same commenter noted that there are numerous factors that influence lag time including (1) watershed characteristics,[140] (2) the fact that watersheds may act as legacy sources releasing Hg when disturbed,[141] (3) the magnitude of emission reductions and subsequent changes in atmospheric deposition need to be weighed against the amount of Hg already in an ecosystem,[142] (4) the distance of an ecosystem from Hg sources,[143] and (5) the fact that Hg deposited to aquatic ecosystems becomes less available for uptake by biota over time.[144] Another commenter stated that additional Mercury Maps assumptions do not allow for considerations of lag in response to changes in: (1) Deposition, (2) legacy sources of Hg such as mining, (3) historical Hg deposition, (4) natural Hg levels in fish, (5) ecosystem dynamics over time, or (6) the relative source contributions over time. Another commenter stated that lag times need to be included in the modeling and be able to vary from watershed to watershed and sometimes even from waterbody to waterbody within a watershed. Several commenters stated that the emission rates of Hg due to U.S. sources have been decreasing for more than a decade, while emissions due to sources outside the U.S. have been increasing. For this reason, the commenter asserted that the system is not at steady-state, a basic premise of the model. Another commenter stated that while the time lag for deposition to reach a waterbody is mentioned in the Hg Risk TSD, there is no discussion of the fact that a

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[135] Seigneur *et al.*, 2006.

[136] *Id.*

[137] Harris., R.C., John W.M. Rudd, Marc Amyot, Christopher L. Babiarz, Ken G. Beaty, Paul J. Blanchfield, R.A. Bodaly, Brian A. Branfireun, Cynthia C. Gilmour, Jennifer A. Graydon, Andrew Heyes, Holger Hintelmann, James P. Hurley, Carol A. Kelly, David P. Krabbenhoft, Steve E. Lindberg, Robert P. Mason, Michael J. Paterson, Cheryl L. Podemski, Art Robinson, Ken A. Sandilands, George R. Southworth, Vincent L. St. Louis, and Michael T. TateRudd, J. W.M., Amyot M., *et al.*, Whole-Ecosystem study Shows Rapid Fish-Mercury Response to Changes in Mercury Deposition. Proceedings of the National Academy of Sciences Early Edition, PNAS 2007 104 (42) pp. 16586–16591; (published ahead of print September 27, 2007).

[138] Orihel D.M., Paterson M.J., Blanchfield P.J., Bodaly R.A., Gilmour C.C., Hintelmann H., 2007. "Temporal Changes in the Distribution, Methylation, and Bioaccumulation of Newly Deposited Mercury in an Aquatic Ecosystem," *Environmental Pollution*, 154, 77–88.

[139] Scudder B.C., Chasar L.C., Wentz D.A., Bauch N.J., Brigham M.E., Moran P.W., Krabbenhoft D.P., 2009. *Mercury in fish, bed sediment, and water from streams across the United States, 1998–2005:* U.S. Geological Survey Scientific Investigations Report 2009–5109, 74 p.

[140] Grigal D.F., 2002. "Inputs and Outputs of Mercury from Terrestrial Watersheds: A Review," *Environmental Review*, 10, 1–39.

[141] Yang H., Rose N.L., Battarbee R.W., Boyle J.F., 2002. "Mercury and Lead Budgets for Lochnagar, a Scottish Mountain Lake and Its Catchment," *Environmental Science & Technology*, 36, 1383–1388.

[142] Krabbenhoft D.P., Engstrom D., Gilmour C., Harris R., Hurley J., Mason R., 2007. Monitoring and Evaluating Trends in Sediment and Water Indicators. In Harris R., Krabbenhoft D., Mason R., Murray M.W., Reash R., Saltman T. (Eds.), *Ecosystem Responses to Mercury Contamination: Indicators of Change.* New York: Society of Environmental Toxicology and Chemistry (SETAC) North America Workshop on Mercury Monitoring and Assessment, CRC, pp. 47–87.

[143] Lindberg S. *et al.* 2007. "A synthesis of progress and uncertainties in attributing the sources of mercury in deposition." Ambio 36(1): 19–32.

[144] Orihel D.M., Paterson M.J., Blanchfield P.J., Bodaly R.A., Hintelmann H., 2008. "Experimental Evidence of a Linear Relationship between Inorganic Mercury Loading and Methylmercury Accumulation by Aquatic Biota," *Environmental Science & Technology*, 41, 4952–4958.

portion of the deposition is unlikely to reach the water at all.

One commenter believes EPA incorrectly implied that its EGU risk estimates using Mercury Maps are underestimated because they do not account for legacy EGU-attributable deposition, which EPA assumes to be higher.

One commenter stated that while EPA properly screened out watersheds with significant current non-air sources of Hg, the EPA did not adequately screen out watersheds with significant Hg contributions from non-air sources, specifically watersheds with historic Hg or gold mining or other industrial Hg discharges. The same commenter stated that EPA's study was not geographically balanced and was dominated by rivers in the coastal region of the southeast that has numerous wetlands, which are favorable locations for methylation and have conditions that are not typical of much of the rest of the U.S.

Response: The EPA disagrees with the commenters who challenged the assumption of a linear proportional relationship between changes in U.S. EGU deposition and fish tissue Hg levels. The EPA specifically asked the SAB to evaluate EPA's assumption of linear proportionality in the relationship between Hg deposition and fish tissue MeHg concentrations, supported by the Mercury Maps analysis. The SAB peer review committee provided the following overall response, which generally supports EPA's approach:

> The SAB agrees with the Mercury Maps approach used in the analysis and has cited additional work that supports a linear relationship between mercury loading and accumulation in aquatic biota. These studies suggest that mercury deposited directly to aquatic ecosystems can become quickly available to biota and accumulated in fish, and reductions in atmospheric mercury deposition should lead to decreases in methylmercury concentrations in biota. The SAB notes other modeling tools are available to link deposition to fish concentrations, but does not consider them to be superior for this analysis or recommend their use. The integration of Community Multiscale Air Quality Modeling System (CMAQ) deposition modeling to produce estimates of changes in fish tissue concentrations is considered to be sound. Although the SAB is generally satisfied with the presentation of uncertainties and limitations associated with the application of the Mercury Maps approach in qualitative terms, it recommends that the document include quantitative estimates of uncertainty available in the existing literature.[145]

The SAB peer review committee specifically addressed the MCM suggested by the commenter and had the following response:

> The SAB agrees with the application of Mercury Maps in this assessment. There are other modeling tools capable of making a national scale assessment, such as the Regional Mercury Cycling Model (R–MCM). However, the R–MCM is more data intensive and the results produced by the two model approaches should be equivalent.
>
> The R–MCM, a steady-state version of the time-dependent Dynamic Mercury Cycling Model, has been publicly available to and used by the EPA (Region 4, Athens, Environmental Research Laboratory) for a number of years. R–MCM requires more detail on water chemistry, methylation potential, etc., and yields more information as well. Substantial data support the Mercury Maps and the R–MCM steady-state results, so that the results of the sensitivity analysis and the outcomes from using the alternative models would be equivalent between the two modeling approaches. Though running an alternative model framework may provide additional reassurance that the Mercury Maps "base case" approach is a valid one, it is unlikely that substantial additional insight would be gained with the alternative model framework.[146]

In addition, the SAB stated, "Since the Mercury Maps approach was developed, several recent publications have supported the finding of a linear relationship between mercury loading and accumulation in aquatic biota.[147] [148] [149] These studies suggested that mercury deposited directly to aquatic ecosystems can become quickly available to biota and accumulated in fish, and that reductions in atmospheric mercury deposition should lead to decreases in methylmercury concentrations in biota. These results substantiate EPA's assumption that proportionality between air deposition changes and fish tissue methylmercury level changes is sufficiently robust for its application in this risk assessment." [150]

Based on the responses of the SAB peer review committee, the EPA's use of the linear proportionality assumption, supported by the Mercury Maps analysis, is well-supported.

The EPA also disagrees with commenters' interpretation of Figure 2–17. As stated in the Hg Risk TSD, while this figure is useful to demonstrate the lack of correlation across watersheds between total deposition of Hg and MeHg concentrations in fish tissue, it is not indicative of the likely correlation between changes in Hg deposition at a given watershed and changes in MeHg concentrations in fish tissue from that watershed. The SAB agreed with this interpretation, noting the importance of Figure 2–17 demonstrating that "spatial variability of deposition rates is only one major driver of spatial variability of fish methylmercury and that variability of ecosystem factors that control methylation potential (especially wetlands, aqueous organic carbon, pH, and sulfate) also play a key role." [151]

In response to recommendations from the SAB, the EPA expanded the discussion of uncertainties associated with the linearity assumption, including uncertainties related to the potential for sampled fish tissue Hg level to reflect previous Hg deposition and the potential for non-air sources of Hg to contribute to sampled fish tissue Hg levels. Each of these sources of uncertainty may result in potential bias in the estimate of exposure associated with current deposition. The EPA took steps to minimize the potential for these biases by (1) only using fish tissue Hg samples from after 1999, and (2) screening out watersheds that either contained active gold mines or had other substantial non-U.S. EGU anthropogenic emissions of Hg. The SAB commented that EPA's approach to minimizing the potential for these biases to affect the results of the risk analysis appears to be sound and that additional criteria that could be applied are unlikely to substantially change the results. As a result, the EPA disagrees with the commenter that EPA's screening process is inadequate. In addition, we conducted several sensitivity analyses to gauge the impact of excluding watersheds with the potential for non-EGU Hg emissions, and found that the results were robust to these exclusions.

In response to specific comments regarding the use of the Mercury Maps model, the EPA clarifies that the Hg Risk TSD did not directly use the Mercury Maps model. Instead, the EPA applied an assumption of linear proportionality between changes in Hg deposition and changes in MeHg concentrations in fish that is supported by the Mercury Maps modeling. By assuming steady-state conditions in apportioning fish tissue Hg levels and risk, the EPA does not attempt to project lag times. Recent research cited by the SAB [152] [153] [154] identifies relatively rapid response of fish tissue Hg to changes in Hg loading, which suggests that fish tissue Hg levels could react more

[145] U.S. EPA–SAB, 2011.

[146] U.S. EPA–SAB, 2011.

[147] Orihel *et al.*, 2007.

[148] Orihel *et al.*, 2008.

[149] Harris *et al.*, 2007.

[150] U.S. EPA–SAB, 2011.

[151] U.S. EPA–SAB, 2011.

[152] Orihel *et al.*, 2007.

[153] Orihel *et al.*, 2008.

[154] Orihel *et al.*, 2007.

quickly to reductions in Hg deposition than previously thought. This finding reduces concern that fish tissue Hg levels could be linked to older patterns of Hg deposition and strengthens the approach used in the revised Hg Risk TSD. While fish tissue may respond rapidly to changes in Hg loading, this does not change the fact that previously emitted Hg from U.S. EGUs can be re-emitted and re-deposited, and thus affect Hg concentration in fish.

2. Characterization of Subsistence Fishing Populations and Exposure Scenario

Comment: Several commenters stated that EPA provides no clear definition of subsistence, near subsistence, or high-end fish consumption, instead assuming that poverty is a direct indication of subsistence fishing and high-end fish consumption. One commenter stated no documentation exists to supports these assumptions. Another commenter stated that EPA's definitions of subsistence fishers in the Hg Risk TSD are not consistent with earlier EPA documents and are used inconsistently throughout the Hg Risk TSD. Several commenters stated that while subsistence fishing can be associated with poverty, poverty does not indicate subsistence fishing. One commenter stated that by including watersheds with as few as 25 members of individuals living in poverty, the EPA overstates risks.

One commenter stated that it is unclear what literature the Agency says "generally supports the plausibility of high-end subsistence-like fishing * * * to some extent across the watersheds" and stated that if other studies exist, the EPA should provide the values for comparison.

One commenter stated that EPA combined two parameters with differing scales to establish the geographic unit used in the Hg Risk TSD risk assessment. The HUC watersheds are based on average about 35 square miles in size, while U.S. census tracts used to identify watersheds relevant for subpopulations of interest—cover a few tenths to hundreds of square miles. Several commenters stated that it is unclear how the analysis handled differences in geographic resolution between watersheds and census tracts were.

One commenter stated that the procedure for assigning census tracts could bias exposure outcomes. For example, the commenter stated that a single influential census tract in a watershed could drive risk, even if the watershed had only a minimal number of fish samples. The commenter stated that this possibility is a concern in urban areas, which account for the majority of census tracts, because these census tracts are more likely to be included in a risk analysis because they have more than 25 people living in poverty. The commenter stated that these census tracts may drive the extremes of the distribution without regard to the actual number of high-level, self-caught fish consumers within their boundaries. The commenter stated that they could not assess the potential bias and noted that EPA did not test the bias by sensitivity analyses.

Several commenters stated that EPA was not clear whether the poverty criteria were applied in all scenarios or just for the high-end female fish consumer scenario. One commenter stated that EPA should apply the minimum 25 source population criteria only to populations of women of childbearing age. One commenter stated that EPA's assumption would result in any densely populated urban census tract with a single fish tissue sample being assigned to a modeled watershed with populations potentially at-risk, regardless of the actual degree of recreational or subsistence fishing taking place there.

Response: The EPA agrees with the comments that subsistence fish consumption was not clearly defined, and we have provided a clearer definition in the revised Hg Risk TSD, however, this clarification does not result in any changes to the quantitative analysis. In the revised Hg Risk TSD, the EPA clarifies that "subsistence fishers" are defined as individuals who rely on noncommercial fish as a major source of protein.[155] This definition is reflected in the range of fish consumption rates used in estimating risk. The likely presence of this type of subsistence fish consumer is supported by available peer reviewed literature (*see* Table 1–5 of the revised Hg Risk TSD). These studies clearly show that a subset of surveyed fishers consumes self-caught fish at the rates cited in the Hg Risk TSD. The SAB peer review concluded that the consumption rates and locations for fishing activity are supported by the data presented in the Hg Risk TSD, and are generally reasonable and appropriate given the available data.[156]

The EPA notes that there is some confusion in the comments related to the size of the watersheds modeled. Several commenters stated that HUC watersheds are 35 km on a side. The commenters appear to be referring to HUC8 classifications. The HUCs are defined for varying spatial resolutions. The geographic unit used as the basis for generating risk estimates is HUC12, which are watersheds about 10 km on a side, which is comparable with the size of the 12 km^2 grid cells in CMAQ, which are 12 km^2. The EPA has also clarified that the specific unit of analysis for this assessment is at the watershed, not enumerated subpopulations.

The EPA only used the U.S. Census tracts to determine whether there are populations in the vicinity of a given watershed, which could increase the potential for a category of subsistence fishers to be active at that watershed. In the revised Hg Risk TSD, the EPA modified the female subsistence scenario to apply equally to all watersheds with fish tissue Hg data based on the likelihood that these populations have the potential to fish at most watersheds. As described in the revised Hg Risk TSD, the EPA made this change in response to SAB's concerns regarding the potential exclusion of watersheds with fewer than 25 individuals and regarding coverage for high-end recreational fish consumption.[157] Thus, concerns regarding the use of census data to select watersheds with the potential for subsistence fishing no longer apply to this scenario. However, for the remaining subsistence scenarios, the EPA continues to use U.S. Census tract-level data to evaluate the presence of a "source population" in the vicinity of the watershed being modeled for risk. In this context, the EPA uses the U.S. Census data to assess whether a socioeconomic status (SES)-differentiated group similar to the particular type of subsistence fisher being modeled (*e.g.*, poor Hispanics) are located in the vicinity of the watershed. If a source population is nearby, then this increases the potential that subsistence fishing activity could occur for that population scenario.

The EPA continues to model risk for white and black subsistence fishers active in the southeast and for Hispanics assessed nationally. In this case, the EPA links poverty with subsistence fishing, as EPA only modeled locations with poor source populations. However, in modeling these three populations, the

[155] U.S. EPA, U.S. Environmental Protection Agency. 2000. *Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories,* Volume 3: Overview of Risk Management. Office of Science and Technology, Office of Water, U.S. Environmental Protection Agency, Washington, DC EPA 823–B–00–007.

[156] U.S. EPA–SAB, 2011.

[157] This change led to a very small increase in the number of watersheds with populations potentially at-risk. In the Hg Risk TSD accompanying the proposed rule, approximately 4 percent of modeled watersheds were excluded based on the SES-based filtering criteria.

EPA asserts that the presence of a poor source population indicates the potential for subsistence fishing activity, rather the presence of such activity. The linkage between poverty and higher rates of subsistence fish consumption is supported by the Burger *et al.* study,[158] which identified substantially higher consumption rates for poor individuals (*see* Table 5 of the study). The EPA acknowledges that subsistence fishing activity by specific subpopulations might only be present across a subset of the watersheds EPA modeled for risk. However, given the stated goal of the analysis to determine the percent of watersheds where the potential exists for exposures to U.S. EGU-attributable Hg to represent a public health hazard, identifying a set of watersheds with the potential for the type of high fish consumption that leads to high Hg exposure is appropriate. The EPA notes that relatively few watersheds (less than 4 percent) have fish tissue Hg data, and, thus, can be included in the risk assessment. Consequently, while there is the potential for including some watersheds in the analysis that may not have currently active subsistence fishing activity, it is likely that EPA excluded other watersheds from the analysis where this type of subsistence fishing activity occurs due to a lack of fish tissue Hg data.

While EPA agrees with the comment that it is likely that exposure to total MeHg through commercial fish consumption represents a more significant risk for the general population than consumption of freshwater fish obtained through self-caught fishing activity, exposure to total MeHg through self-caught fish consumption is the most significant risk for subsistence fishing populations and high-end recreational fishers. For the subset of these populations that focus their fishing activity in freshwater streams and lakes, it is also the case that they will experience a higher fraction of MeHg exposure attributable to U.S. EGU Hg emissions. As a result, the EPA focused the risk assessment on subsistence fishers active at inland freshwater watersheds because they are likely to experience the highest levels of individual risk as a result of exposure to U.S. EGU-attributable Hg.

3. Cooking Loss Adjustment Factor

Comment: Several commenters stated that EPA did not justify the selection of a cooking loss factor of 1.5 that, according to one commenter, increases estimated intake by 50 percent, thus increasing the daily MeHg intake rate by a constant factor of 33 percent and also increasing any resulting (HQ) risk estimate by a similar factor. Several commenters stated that the source of EPA's selected loss factor[159] reported a range of cooking losses from 1.1 to 6. Several commenters cite several studies that report no or highly variable changes in MeHg levels as a result of cooking fish.[160] [161] [162] [163] [164] One commenter suggested that EPA's cooking loss adjustment factor of 1.5 is at the high-end of the values supported by the literature. Another commenter stated that EPA has used other adjustment factors in previous documents, and that the adjustment factor should not be fixed across different populations given potential differences in cooking practices. Several commenters noted that the cooking loss adjustment factor should only be applied to estimates of consumption rates for prepared fish, and that some sources of consumption rates are based on raw fish.

Response: The EPA disagrees with the commenters that the selection of the cooking loss factor of 1.5 is not justified by the literature. The EPA also disagrees with the comment that the cooking loss adjustment factor of 1.5 is at the high-end of the range of values in the literature. The EPA selected the Morgan study[165] as the basis for the food preparation/cooking adjustment factor because it focused on the types of freshwater fish species representative of what might be consumed by subsistence fishing populations (*i.e.*, walleye and lake trout). This study[166] provides a range of adjustment factors for each fish type including 1.1 to 1.5 for walleye and 1.5 to 2.0 for lake trout. Given these two ranges, the EPA determined it to be reasonable to take an intermediate value between the two ranges (*i.e.*, 1.5), rather than focus on either the highest or lowest values, which is not the most conservative assumption that the EPA could have made. This study[167] also explains that preparation/cooking of fish results in an increase in MeHg levels per unit fish because Hg concentrates in the muscle, while preparation/cooking tends to reduce non-muscle elements (*e.g.*, water, bone, fat).

Regarding the alternative studies identified by the commenters, the EPA disagrees that these studies considered collectively contradict the cooking loss factor in the analysis. Specifically, the first study[168] may have included measurement of non-fish components added to dishes (*e.g.*, onions, heavy breading etc.), which could dilute the post-cooking Hg measurements and give the appearance of a cooking loss even as actual fish tissue Hg levels could have increased. In the second study,[169] the fish species are saltwater and not freshwater, and the authors note that the reduction of water and fat could increase in the Hg concentration without changing absolute content. The third study focused on measurement of *bioaccessible Hg* in raw and cooked fish.[170] However, available information currently allows us to specify the risk model in terms of total Hg intake, not bioaccessible Hg, thus, this article is potentially informative for guiding future research and methods development, not the current risk assessment. The fourth study[171] found a modest but statistically insignificant increase in Hg levels for most of the cooking methods assessed, which is directionally consistent with EPA's cooking loss adjustment. The fifth study[172] only addressed the issue qualitatively, thus cannot be used for the cooking loss factor. When considered collectively, the EPA disagrees that the additional studies identified by the commenter contradict the cooking loss factor used in the risk assessment and maintains that the Morgan study[173] remains the most

[158] Burger, J., 2002. "Daily Consumption of Wild Fish and Game: Exposures of High End Recreationists," *International Journal of Environmental Research and Public Health*, 12 (4), 343–54.

[159] Morgan, J.N., M.R. Berry, and R.L. Graves. 1997. "Effects of Commonly Used Cooking Practices on Total Mercury Concentration in Fish and Their Impact on Exposure Assessments." *Journal of Exposure Analysis and Environmental Epidemiology* 7(1):119–133.

[160] Armbruster G., Gerow K.G., Lisk D.J., 1988. "The Effects of Six Methods of Cooking on Residues of Mercury in Striped Bass," *Nutrition Reports International*, 37, 123–126.

[161] Gutenmann, W.H. and Lisk D.J., 1991. "Higher Average Mercury Concentration in Fish Fillets after Skinning and Fat Removal," *Journal of Food Safety*, 11, 99–103.

[162] Farias L.A., Favaro, D.I., Santos J.O., Vasconcellos M.B., *et al.*, 2010. "Cooking Process Evaluation on Mercury Content in Fish," *Acta Amazonia*, 40 (4), 741–748.

[163] Perelló G., Martí-Cid R., Llobet J.M., Domingo J.L., 2008. "Effects of Various Cooking Processes on the Concentrations of Arsenic, Cadmium, Mercury, and Lead in Foods," *Journal of Agricultural and Food Chemistry*, 156 (22), 11262–11269.

[164] Torres-Escribano S., Ruiz A., Barrios L., Vélez D., Montoro R., 2011. "Influence of Mercury Bioaccessibility on Exposure Assessment Associated with Consumption of Cooked Predatory Fish in Spain," *Journal of the Science of Food and Agriculture*, 91 (6), 981–6.

[165] Morgan *et al.*, 1997.

[166] *Id.*

[167] *Id.*

[168] Farias *et al.*, 2002.

[169] Perelló *et al.*, 2008.

[170] Torres-Escribano *et al.*, 2011.

[171] Armbruster *et al.*, 1988.

[172] Gutenmann *et al.*, 1991.

[173] Morgan *et al.*, 1997.

applicable for characterizing cooking/preparation effects on Hg concentrations in fish.

The EPA agrees that application of the cooking loss adjustment factor is appropriate if the fish consumption rates are for *as cooked* or *as consumed* and not for raw fish. Careful review of the three studies used in the risk assessment to identify subsistence fisher consumption rates suggests that all three represent annual-average daily intakes (g/day) of *as consumed* or *as cooked* fish. One study stated that they used models of portion or meal size servings (the size of the serving the respondent regularly eats).[174] Therefore, the EPA interprets the fish consumption rates provided in this study[175] as representing *as cooked/prepared* and not for raw fish and for that reason, application of a preparation/cooking adjustment factor is required. Another study[176] used different sized models of cooked fish filets and therefore these consumption rates are also interpreted as represented *as cooked/prepared* and not raw fish. One study[177 178] queried survey responders for meal portion or serving size and therefore, the consumption rates do represent *as cooked/prepared*. Because all three studies provide consumption rates based on *as cooked/prepared* or as consumed, it is appropriate to apply the cooking loss adjustment factor in modeling exposure.

4. Fish Consumption Rates and Fish Tissue Hg Characterization

Comment: One commenter stated that in the past the Agency has recommended various default consumption rates (in the general range of 130 to <150 g/day) to provide default intakes for subsistence fishers under the *Risk Assessment Guidance for Superfund (RAGS) or the Fish Advisory Guidance*.[179 180] The commenter stated that these default consumption rates are derived from various studies and generally are based on 90th or 99th percentile distribution estimates. Another commenter stated that EPA's use of the 99th percentile fish consumption for its risk analysis is inconsistent with the Agency's risk assessment guidelines, which recommend evaluating a reasonable maximum exposure ("RME") scenario,[181] which equates to about a 95th percentile fish consumption value. The same commenter stated that EPA applied the 99th percentile to a "small survey of 149 South Carolina female anglers" to calculate an ingestion rate of 373 grams per day (g/day). The commenter stated that if the 95th percentile is used the ingestion rate would be 173 g/day and if the default ingestion rate for determining ambient water standards is used the ingestion rate would be 142 g/day.

Several commenters stated that EPA based its fish consumption rates used in the risk analysis on a limited number of studies and that those studies are poorly documented.

Another commenter stated that EPA should summarize available supporting studies by basic study content, characteristics, design, size, demographics, dietary recall period, and fish intake rates by demographic variables. According to the commenter, this summary would support the scientific validity of the assessment and better illustrate the potential variability and uncertainty involved in extrapolating data from small populations to the national-scale. The commenter also noted that the three studies actually used to provide subsistence population estimates, which were extrapolated to the national-scale, included a limited number of individuals living in diverse and localized areas.

One commenter stated that the assumption with the greatest impact on risk is the fish consumption rate. That same commenter stated that using 99th percentile ingestion rate dramatically increases HQ and IQ loss compared to the 50th percentile ingestion rate. The commenter stated that when an estimate of the 95th percentile ingestion rate of the 15 to 44 year old female population is considered, the HQ is a tenth of the value computed with the 99th percentile high-end female fisher.

One commenter stated that EPA provides broad summary statistics of its fish tissue data in Table 5–2 of the Regulatory Impact Analysis (RIA), but the summary does not allow an assessment of the representativeness and robustness of the underlying data for the risk assessment, especially at the tails of the distribution. The commenter stated that the table does not include a median statistic and does not provide any information on the number of lakes and river segments in each watershed. According to the commenter, an analysis of EPA's database by the SAB indicated that 60 percent of the watersheds with fish Hg data from rivers have risks calculated based upon a sample size of one or two fish. The commenter stated that it is not reasonable to base a significant policy and regulation decision on watersheds where exposure is based on a single fish sample in a single water body within it.

Several commenters criticized EPA's use of the 75th percentile fish tissue MeHg level in a watershed. One commenter stated that EPA provided no rationale for its decision to choose the highest of the 75th percentile for fish Hg levels among rivers and lakes within the HUC. Several commenters stated that subsistence fishers are less likely to target larger fish relative to recreational fishers. Several commenters suggested that EPA include a sensitivity analysis using the mean or median fish MeHg level in a watershed. One commenter also stated that EPA arbitrarily inflated the risk estimates by assuming consumption of only fish greater than 7 inches and choosing the largest of the 75th percentile of fish Hg levels from these larger fish (*i.e.*, larger than 7 inches) for rivers and lakes. That same commenter suggested using the median of all size fish, not just those over 7 inches.

One commenter stated that EPA should quantify adverse effects from the ingestion of MeHg in seafood in addition to ingestion of MeHg from self-caught freshwater fish. According to the commenter, recent studies demonstrate that were EPA to take into account consumption of seafood, MeHg consumption in the U.S. is of even greater concern.

Response: The EPA acknowledges that the focus of the Hg Risk TSD is characterizing risk for the groups likely to experience the greatest U.S. EGU-attributable Hg risk, which are subsistence fishing populations active at inland freshwater lakes and rivers. Specifically, within that subsistence fishing population, the EPA is interested in those individuals who are most at-risk, which includes those who consume the most fish. For that reason, the EPA considered a range of high-end fish consumption rates including the 99th percentile representing the most highly-exposed individuals. In responding to the SAB peer review, the EPA clarified this focus in the

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[174] Burger *et al.*, 2002.

[175] *Id.*

[176] Shilling, Fraser, Aubrey White, Lucas Lippert, Mark Lubell (2010). Contaminated fish consumption in California's Central Valley Delta. Environmental Research 110, p. 334–344.

[177] Dellinger JA. 2004. "Exposure assessment and initial intervention regarding fish consumption of tribal members of the Upper Great Lakes Region in the United States." *Environ Res* 95:325–340.

[178] Personal communication, Dr. Dellinger, September 27, 2011.

[179] U.S. EPA. 1991. *Risk Assessment Guidance for Superfund (RAGS)*. Part C 1991 EPA/9285.7–01C. October.

[180] U.S. EPA. 2000. *National Guidance: Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories*, Volume 2. EPA 823–B–00–008, November.

[181] U.S. EPA. 1989. *Risk Assessment Guidance for Superfund (RAGS)*. EPA/540/1–89/002. December.

introduction to the revised Hg Risk TSD and changed the full title to *revised Technical Support Document: National-Scale Assessment of Mercury Risk to Populations with High Consumption of Self-caught Freshwater Fish.*

The EPA agrees that the fish consumption rate is an important factor in calculating risk from exposure to MeHg in fish. The EPA acknowledges that the distribution of fish consumption rates is positively skewed, which means that at higher percentiles (*e.g.,* 90th, 95th, and 99th) there is a substantial increase in ingestion rates relative to the mean or median. The revised Hg Risk TSD includes a reasonableness check on the amount of fish consumed (as a daily value) reflected in the different rates. While the 99th percentile consumption rates for the subsistence female fisher (373 g/day) is substantially higher than the 90th or 95th percentile values (123 and 173 g/day respectively), the 99th percentile value translates into a 13-ounce meal. While this represents a large serving, it is still reasonable if representing an individual who receives all of their meat protein from self-caught fishing, and the 13 ounces per day do not have to be eaten all at one meal. The higher consumption rates (i.e., greater than 250 g/day) are supported by all three studies used in the risk assessment, and therefore, there is support across studies near the upper bound of likely consumption rates in this range. The EPA acknowledges uncertainty associated with estimating high-end percentile values in these studies due to relatively low sample sizes for some population groups. However, even if a few individuals reported these high self-caught fish consumption rates, making it difficult to characterize the population percentiles they represent, the values still suggest that these levels of high fish consumption exist among surveyed individuals. To determine whether a public health hazard could exist, the EPA asserts that it is reasonable to include these consumption rates as representative of the most at-risk populations. In these cases, however, the EPA acknowledges that it is important to highlight uncertainty associated with characterizing the specific population percentile that these ingestion rates represent, and EPA has done so in the revised Hg Risk TSD.

The EPA disagrees with the comment that high consumption rates are poorly documented. Evidence of these high fish consuming populations can be found in surveys [182] and specialized studies.[183] [184] [185] [186] [187] Several studies identified additional fishing populations with subsistence or near subsistence consumption rates, including urban fishing populations (including low-income populations),[188] [189] [190] Laotian communities,[191] and Hispanics. The EPA participated in 1999 in a project investigating exposures of poor, minority communities in New York City to a number of contaminants including Hg, which found these populations can have very high fish consumption rates.[192] The SAB concluded that the consumption rates and locations for fishing activity are supported by the data presented in the Hg Risk TSD, and are generally reasonable and appropriate given the available data.[193]

The EPA agrees that the Hg Risk TSD would be improved by clarifying that the literature review focused on identifying studies that characterize subsistence fish consumption for groups active at freshwater locations within the U.S., and EPA has revised the Hg Risk TSD accordingly. In the Hg Risk TSD, the EPA summarized important study attributes for the source studies used to obtain fish consumption rates. This information was provided in Table C–1 in an appendix. To improve clarity, the EPA moved the summary table to the main body in the revised Hg Risk TSD. In identifying these studies, the EPA focused on surveys for subsistence fishers that were applicable at the broader regional or national level. In the Hg Risk TSD, the EPA acknowledged the smaller sample sizes for some of the subsistence fisher groups, and in several cases the EPA did not use the 99th percentile consumption rates because the sample sizes were too low to support this level of resolution. This decision did not affect EPA's finding of a hazard to public health, which is based on the results for the female subsistence fishing population, which has an estimate of the 99th percentile consumption rate that is supported by an adequate sample size.

The EPA disagrees with the comment that it did not provide a rationale for choosing the 75th percentile fish tissue concentration across lakes and rivers in a watershed. However, the EPA modified the methodology based on evaluation of the number of samples within each watershed (responding to a recommendation from the SAB). In the revised methodology, the EPA computes the 75th percentile value at each sampling site within a watershed. The EPA then computed the average of the site-specific 75th percentile fish tissue Hg values within a given watershed. This approach does not differentiate between rivers and lakes and reflects an improved treatment of behavior, allowing for fishers to choose among multiple fishing sites within a watershed.

The EPA generally agrees with the comment that some fraction of subsistence fishers likely consume fish without consideration for size (given dietary necessity), however, the EPA considers it reasonable to assume that a subset of subsistence fishers could target larger fish in order to maximize the potential consumption per unit of fishing effort. The EPA uses this subset of subsistence fishers targeting larger fish, which is represented by the 75th percentile fish tissue value, in the risk assessment. In addition, including the female subsistence fishing population in the analysis also provides coverage for high-end recreational anglers who target larger freshwater fish. The SAB commented that: "Using the 75th percentile of fish tissue values as a reflection of consumption of larger, but not the largest, fish among sport and subsistence fishers is a reasonable approach and is consistent with published and unpublished data on predominant types of fish consumed." [194] The SAB suggested that EPA include a sensitivity analysis based on use of the median value, and EPA has done so in the revised Hg Risk TSD. This sensitivity analysis showed that using the median estimates had only a small impact on the number and percent of modeled watersheds with

[182] Burger *et al.,* 2002.

[183] Burger, J., K. Pflugh, L. Lurig, L. Von Hagen, and S. Von Hagen. 1999a. "Fishing in Urban New Jersey: Ethnicity Affects Information Sources, Perception, and Compliance." *Risk Analysis* 19(2): 217–229.

[184] Burger, J., Stephens, W. L., Boring, C. S., Kuklinski, M., Gibbons, J. W., Gochfeld M. 1999b. "Factors in Exposure Assessment: Ethnic and Socioeconomic Differences in Fishing and Soncumption of Fish Caught along the Savannah River." *Risk Analysis,* Vol. 19, No. 3, p. 427.

[185] California Environmental Protection Agency (CalEPA). 1997. *Chemicals in Fish Report No. 1: Consumption of Fish and Shellfish in California and the United States Final Draft Report.* Pesticide and Environmental Toxicology Section, Office of Environmental Health Hazard Assessment, July.

[186] Tai, S. 1999. "Environmental Hazards and the Richmond Laotian American Community: A Case Study in Environmental Justice." Asian Law Journal 6: 189.

[187] Corburn, J. 2002. "Combining community-based research and local knowledge to confront asthma and subsistence-fishing hazards in Greenpoint/Williamsburg, Brooklyn, New York." *Environmental Health Perspectives* 110(2).

[188] Burger *et al.,* 1999a.

[189] Burger *et al.,* 1999b.

[190] CalEPA, 1997.

[191] Tai, 1999.

[192] Corburn, 2002.

[193] U.S. EPA–SAB, 2011.

[194] U.S. EPA–SAB, 2011.

populations potentially at-risk from U.S. EGU-attributable MeHg exposures. In the revised Hg Risk TSD, the EPA clarified that the 7-inch cutoff represents a minimum size limit for a number of key edible freshwater fish species established at the State-level. For example, Pennsylvania establishes 7 inches as the minimum size limit for both trout and salmon (other edible fish species such as bass, walleye and northern pike have higher minimum size limits).[195]

The EPA disagrees with the comment that it is not reasonable to use watersheds where only a single fish sample is available. Although it is generally preferred to have multiple samples, the SAB noted that using a single sample is likely to underestimate the 75th percentile fish MeHg concentration and is, therefore, likely to underestimate the risk estimates for those watersheds. The SAB suggested that EPA conduct additional analyses of the fish tissue MeHg data, which EPA has done and included in the revised Hg Risk TSD. The revised Hg Risk TSD includes information on the number of watersheds modeled in the risk assessment with various fish tissue Hg samples sizes (e.g., 1, 2, 3–5, 6–10 and >10 measurements).

5. Reference Dose (RfD) for MeHg and Hg Health Effects Studies

Comment: Several commenters stated that EPA's RfD[196] is based on sound science, which was supported by the findings of the NAS Study,[197] and that EPA appropriately applied the RfD in the Hg risk assessment. The commenters also stated that recent studies find clear associations between maternal blood Hg levels and delayed child development and cardiovascular effects, as well as potential for effects due to exposure to pollutant mixtures including lead.

However, many commenters expressed concerns regarding EPA's use of the MeHg RfD as a benchmark for health risk. Several commenters raised concerns claiming that EPA has not incorporated the best available Hg toxicological data into the RfD, which results in a flawed analysis and an overestimate of the impact of Hg emissions on human health.

Several commenters stated that, when deriving the RfD, the EPA relied on the flawed Faroe Islands' children study and ignored the Seychelles Islands study,[198] which did not confirm any harm on children due to MeHg exposure. According to the commenters, application of the Faroe Island study is suspect because (1) the raw data from the study have never been made available for independent analysis and scrutiny, (2) there is potential for confounding by polychlorinated biphenyls (PCBs) and lead, (3) population exposure to MeHg was through consumption of highly contaminated pilot whale meats and blubbers, and (4) exposure levels in the U.S. remain lower than those observed in the primary study. One commenter also notes that (1) Seychelles Islanders consume far more fish than Americans do; (2) the amount of MeHg in the U.S. population is much lower than the Seychelles Islanders; and (3) all ocean fish contain about the same amount of MeHg, so MeHg intake per fish meal is similar between Americans and Seychelles Islanders. However, another commenter stated that industry arguments against using the Faroe Islands study fail to acknowledge that the study results were consistent with studies in the Seychelles Islands, New Zealand,[199] and Poland.[200]

One commenter criticized EPA for using a linear dose-response model for the RfD-based HQ metric and the IQ metric. Another commenter stated that the RfD assumes a threshold dose below which an appreciable risk of adverse effects is unlikely, and NAS did not evaluate whether MeHg exposure data were better fit by a linear or non-linear model or by a threshold or non-threshold model.

Several commenters stated that EPA's MeHg RfD is more conservative than "safe" levels determined by other federal agencies and claim that EPA assigned unusually high uncertainty factors. Several commenters stated that EPA's use of the 1999 National Health and Nutrition Examination Survey (NHANES) blood Hg levels show a downward trend since 1999, and the levels have been below the RfD since 2001.

One commenter stated that a study by Texas Department of State Health Services (DSHS, 2004)[201] determined that among subsistence fishers who eat fish from Caddo Lake with elevated MeHg, women of child-bearing years did not have blood Hg levels greater than the RfD. Thus, according to the commenter, the connection between MeHg in fish and adverse health effects in the U.S. is not fully understood and could involve other factors, including the protective effects of fatty acids and selenium in fish, which EPA did not taken into account.

Two commenters claim that EPA uses the RfD as if it were an absolute threshold for health risk in the risk assessment even though the RfD methodology is a screening tool for deciding when risks clearly do not exist.

Several commenters recommended adding qualitative discussions to the Hg Risk TSD regarding several aspects of uncertainty, including uncertainty in the RfD, uncertainty in extrapolating a dose-response relationship between MeHg exposure and change in IQ, uncertainty in extrapolating the dose-response relationship from marine fish and marine mammals to freshwater fish, and uncertainty due to potential confounding by PCBs in marine species.

Several commenters raised concerns regarding the relationship between MeHg exposure and IQ loss. Two commenters stated that changes in IQ are not a well-defined health consequence of MeHg exposure. One commenter stated that the SAB had reservations about EPA's use of IQ loss. Two commenters questioned whether IQ impacts would even occur because in Japan and Korea, where the maternal blood Hg levels are higher than in the U.S., there is no evidence of adverse effects. Another commenter cited a study[202] that found verbal IQ scores for children from mothers with no seafood intake were 50 percent more likely to be in the lowest quartile. One commenter questions using an IQ risk metric threshold of >1 or >2 points because variation in IQ measures and the intra-individual variation in IQ are higher than the threshold.

Several commenters question the relationship between cardiovascular effects and MeHg exposure. Two

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[195] Pennsylvania Fish and Boat Commission. 2011. *Summary Book: 2011 Pennsylvania Fishing Laws & Regulations* available at: *http://fishandboat.com/fishpub/summary/inland.html.*

[196] U.S. Environmental Protection Agency—Integrated Risk Information System (U.S. EPA–IRIS). 2001. Methylmercury (MeHg) (CASRN 22967–92–6). Available at *http://www.epa.gov/iris/subst/0073.htm.*

[197] NAS, 2000.

[198] Budtz-Jorgensen E, Debes F, Weihe P, Grandjean P. 2005. "Adverse Mercury Effects in 7-Year-Old Children Expressed as Loss in "IQ"." EPA–HQ–OAR–2002–0056–6046.

[199] Kjellstrom, T; Kennedy, P; Wallis, S; *et al.* 1986. *Physical and mental development of children with prenatal exposure to mercury from fish. Stage 1: Preliminary test at age 4.* Natl Swed Environ Protec Bd, Rpt 3080 (Solna, Sweden).

[200] Wieslaw Jedrychowski *et al.* 2006. "Effects of Prenatal Exposure to Mercury on Cognitive and Psychomotor Function in One-Year-Old Infants: Epidemiologic Cohort Study in Poland," 16 Annals of Epidemiology 439.

[201] DSHS. 2005. *Health Consultation: Mercury Exposure Investigation Caddo Lake Area-Harrison County Texas.* Agency for Toxic Substances and Disease Registry. *http://www.tceq.state.tx.us/assets/public/comm_exec/pubs/sfr/085.pdf.*

[202] Hibbeln JR, Davis JM, Steer C, Emmett P, Rogers I, Williams C, *et al.*, 2007. "Maternal seafood consumption in pregnancy and neurodevelopmental outcomes in childhood (ALSPAC study): an observational cohort study. " Lancet 369:

commenters cited studies examining the relationship between MeHg exposure and cardiovascular effects,[203] [204] [205] [206] [207] [208] but concluded that it seems premature to use these studies to establish a dose-response relationship.

Several commenters assert that the risks from eating seafood are low relative to the benefits, that fish advisories can limit the beneficial aspects of fish consumption, and that fish advisories are often unsuccessful in changing behavior.[209] [210] One commenter noted the important protective role of dietary selenium against MeHg toxicity because the binding affinity of Hg to Se is much higher than binding to sulfur.

Response: The EPA agrees with commenters that state the MeHg RfD is the appropriate health value for determining elevated risks from MeHg exposure and disagrees with commenters that state otherwise. At this time, the EPA is neither reviewing nor revising its 2001 RfD for MeHg. The 2001 RfD for MeHg is EPA's current peer-reviewed RfD, which is the value EPA uses in all its risk assessments. The EPA's RfD is based on multiple benchmark doses, and RfDs were calculated on various endpoints using the three extant large studies of childhood effects of in utero exposure: Faroe Islands, New Zealand, and an integrative measure including data from Seychelles. The EPA did not choose to base the MeHg RfD solely on results from the Seychelles Islands, as both the NAS [211] and an independent scientific review panel convened as part of the IRIS process [212] advised strongly against using results from a study that at the time had not shown an association between MeHg exposure and adverse effects. Further, the EPA disagrees with comments stating that EPA based the MeHg RfD solely on results from the Faroe Islands population and disagrees that the information underlying the RfD is "poorly explained". The EPA has provided detailed documentation for the choices underlying calculation of the RfD.[213] [214] [215] To correct a misunderstanding by the commenter, the data underlying the Faroe Islands study have been previously published in the peer reviewed literature.

The EPA disagrees that it did not incorporate the latest Hg data to support the appropriate and necessary finding. It is the policy of EPA to use the most current peer reviewed, publicly available data and methodologies in its risk assessments. However, the EPA noted in the preamble to the proposed rule that "data published since 2001 are generally consistent with those of the earlier studies that were the basis of the RfD, demonstrating persistent effects in the Faroe Island cohort, and in some cases associations of effects with lower MeHg exposure concentrations than in the Faroe Islands. These new studies provide additional confidence that exposures above the RfD are contributing to risk of adverse effects, and that reductions in exposures above the RfD can lead to incremental reductions in risk." However, the EPA has not completed a comprehensive review of the new literature, and as such, it would be premature to draw conclusions about the overall implications for the RfD.

The EPA agrees that EPA's RfD is not the same as the levels used by other federal agencies. In their advice to the EPA on the appropriate bases for a MeHg RfD, NAS specifically recommended that EPA use neither the study nor the uncertainty factor employed by the Agency for Toxic Substances Disease Registry (ATSDR) in the calculation of the minimal risk level.[216]

The EPA disagrees that the uncertainty factor is "unusually high". The uncertainty factor used in calculation of EPA's peer-reviewed RfD is small (10 fold); half of this factor is to account for measured variability in human pharmacokinetics, which is based on advice of the NAS [217] and an independent panel of scientific peer reviewers convened as part of the IRIS process.[218]

The IRIS makes this statement regarding a threshold for MeHg, "It is also important to note that no evidence of a threshold arose for methylmercury-related neurotoxicity within the range of exposures in the Faroe Islands study. This lack [of a threshold] is indicated by the fact that, of the K power models, K = 1 provided a better fit for the endpoint models than did higher values of K." [219]

The EPA disagrees that it is using the MeHg RfD as an absolute bright line for health effects in the risk assessment. As stated in the preamble to this proposed rule, the RfD is an estimate of a daily exposure to the human population that is likely to be without an appreciable risk of deleterious effects during a lifetime. The EPA also stated that no RfD defines an exposure level corresponding to zero risk. Because mercury is a cumulative neurotoxin, it is important to distinguish health effects from public health hazard. Within the context of the appropriate and necessary finding, we interpret a public health hazard as risk, rather than certain occurrence of health effects.

The EPA disagrees that exposure levels in the U.S. are lower than those in the Faroe Islands study. Exposure to MeHg in the U.S. has been reported at the same levels as those published in the Faroe Islands.[220] One study notes that in the NHANES data (1999 to 2004), the highest five percent of women's blood Hg exceeded 8.2 microgram per liter (μg/L) in the Northeast U.S. and 7.2 μg/L in coastal areas.[221] Higher levels have been reported among subjects known to consume fish. For example, one study reported mean blood Hg for adult women to be 15 μg/L; range for

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[203] Roman HA, Walsh TL, Coull BA, Dewailly É, Guallar E, Hattis D, *et al.*, 2011. Evaluation of the Cardiovascular Effects of Methylmercury Exposures: Current Evidence Supports Development of a Dose–Response Function for Regulatory Benefits Analysis. Environ Health Perspect 119:607–614.

[204] Guallar E, Sanz-Gallardo MI, van't Veer P, *et al.*, 2002. "Mercury, fish oils, and the risk of myocardial infarction." N Engl J Med.;347:1747.

[205] Virtanen JK, Voutilainen S, Rissanen TH, *et al.*, 2005. "Mercury, fish oils, and risk of acute coronary events and cardiovascular disease, coronary heart disease, and all-cause mortality in men in eastern Finland." Arterioscler Thromb Vasc Biol. 2005;25:228.

[206] Yoshizawa, Rimm, Morris, Spate, Hsieh, Spiegelman, Stampfer, Willett. "Mercury and the Risk of Coronary Heart Disease in Men," N Engl J Med 2002; 347:1755–1760.

[207] Hallgren CG, Hallmans G, Jansson JH, *et al.*, 2001. Markers of high fish intake are associated with decreased risk of a first myocardial infarction. Br J Nutr: 86:397.

[208] Mozaffarian, Dariush. 2011. "Mercury Exposure and Risk of Cardiovascular Disease in Two U.S. Cohorts," N Engl J Med 364: 1116–1125.

[209] Hibbeln *et al.*, 2007.

[210] Mozaffarian, *et al.*, 2011.

[211] NAS, 2000.

[212] U.S. EPA. 2001b. Responses to Comments of the Peer Review Panel and Public Comments on Methylmercury. Available on the Internet at *http://www.epa.gov/iris/supdocs/methpr.pdf.*

[213] U.S. EPA, 2001a. Water Quality Criterion for the Protection of the Human Health: MethylmercuryEPA–823–T–01–001, available at *http://water.epa.gov/scitech/swguidance/standards/criteria/aqlife/pollutants/methylmercury/index.cfm.*

[214] U.S. EPA–IRIS, 2001.

[215] Rice D, Schoeny R, Mahaffey K. 2003. "Methods and Rationale for Derivation of a Reference Dose for Methylmercury by the U.S. EPA." Risk Analysis 23(1)107–115.

[216] NAS, 2000.

[217] Id.

[218] U.S. EPA, 2001b.

[219] U.S. EPA–IRIS, 2001.

[220] Schober Susan E, Sinks Thomas H, Jones Robert L, Bolger P Michael, McDowell Margaret, Osterloh John, Garrett E Spencer, Canady Richard A, Dillon Charles F, Sun Yu, Joseph Catherine B, Mahaffey Kathryn R. Blood mercury levels in U.S. children and women of childbearing age, 1999–2000. JAMA. 2003 Apr 2; 289(13): 1667–1674.

[221] Mahaffey, K.R., R.P. Clickner and R.A. Jeffries. 2009. Adult Women's Blood Mercury Concentrations Vary Regionally in the U.S.: Association with Patterns of Fish Consumption (NHANES 1999–2004). *Environ. Health Perspect.*, 117: 47–53.

men and women was 2 to 89.5 μg/L.[222] Note that some publications have reported Hg effects in U.S. populations at or below the current U.S. RfD.[223] [224] Also, the EPA disagrees with the commenter stating all ocean fish throughout the world contain about the same amount of MeHg. Marine fish in commerce differ widely in Hg concentration by species, and fish within the same species but caught at different locations have variable amounts of Hg in their tissues.[225] [226]

The EPA disagrees that there is a statistically discernible downward trend in the NHANES data on blood Hg. The EPA is unaware that a formal statistical analysis for temporal trends has been completed for NHANES data on blood Hg levels for the period 1999 to 2008. Mahaffey*et al.,* evaluating NHANES data collected 1999 to 2004 for women at child-bearing age, could "not support the conclusion that there was a general downward trend in blood Hg concentrations over the 6-year study period." [227] However, the same publication noted that "there was a decline in the upper percentiles reflecting the most highly exposed women" having blood Hg concentration greater than established levels of concern. Visual observations of the data show a slight decrease in Hg blood level concentrations from 1999–2008 at the geometric mean, but this decrease may not be statistically significant. The EPA remains concerned that substantial numbers of women of childbearing age in the U.S. may have blood Hg levels that are equivalent to exposures at or above the RfD. While mean and 95th percentiles from recent NHANES data are below the blood Hg concentration equivalent to the RfD, blood levels for some portions of the population (high consumers of fish, for example) show exposures above this level. One study estimated very high blood Hg levels at the 99th percentile for females of child-bearing age.[228] Other published studies have shown that various population groups can have high blood Hg levels.[229] [230] [231] [232] [233] For example, one study found that 83 percent of the NHANES Asian population exceeded the RfD-equivalent blood mercury level.[234]

The EPA disagrees with the commenter regarding confounding by PCBs and lead. Exposure to MeHg in the Faroe Islands was largely from consumption of pilot whale meat; exposure to PCBs was found in the portion of the population who also consume whale blubber. Numerous analyses have shown neurobehavioral effects of PCBs; however, the effects of MeHg and PCB in the Faroe Islands study are separable.[235] The EPA also documented the independence of PCB and MeHg effects in the Faroe Islands population.[236] The National Institute of Environmental Health Sciences (NIEHS) concluded that both PCB and Hg had adverse effects.[237] The NAS concluded that there was no empirical evidence or theoretical mechanism to support the opinion that *in utero* Faroese exposure to PCBs exacerbated the reported MeHg effect.[238] A second set of analyses found that the effect of prenatal PCB exposure was reduced when the data were sorted into tertiles by cord PCB concentrations.[239] These analyses support a conclusion that there are measurable effects of MeHg exposure in the Faroese children that are not attributable to PCB toxicity. We also note that there was no report of lead exposure in the Faroe Islands population.

The EPA disagrees with the commenter's assertion that the connection between MeHg in fish and observed health effects is not understood due to evidence from the cited Texas study.[240] This is an exposure study rather than a study on measures of neurobehavioral or any other health endpoint. TCEQ noted that none of the Caddo Lake study participants had blood Hg levels above the benchmark dose level (BMDL) of 5.8 μg/L (one of the several used by EPA in the calculation of the MeHg RfD). The BMDL is not a "no effect" level. Rather it is an effect level for a percentage of the population. The EPA has noted in correspondence with TCEQ that, as an exposure study, the Caddo Lake study may be representative of the surrounding population; however, the sample size is very small. It is not appropriate to extrapolate from Caddo Lake to larger regional or national populations.

The EPA is aware of the possibility of both interactions among environmental contaminants and cumulative effects of pollutants that produce the same adverse endpoint. The EPA guidance exists for dealing with such scenarios.[241] [242] [243] [244] The Agency's concern with the likelihood of human exposure to multiple contaminants is

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[222] Hightower Jane M, Moore Dan. Mercury levels in high-end consumers of fish. Environ Health Perspect. 2003 Apr; 111(4): 604–608.

[223] Oken, E., Radesky, J.S., Wright, R.O., Bellinger, D.C., Amarasiriwardena, C.J., Kleinman, K.P., Hu, H., Gillman, M.W. 2008. Maternal fish Intake during Pregnancy, Blood Mercury Levels, and Child Cognition at Age 3 Years in a U.S. Cohort. *American Journal of Epidemiology, 167(10),* 1,171–1,181.

[224] Lederman, Sally Ann Robert L. Jones, Kathleen L. Caldwell, Virginia Rauh, Stephen E. Sheets, Deliang Tang, Sheila Viswanathan, Mark Becker, Janet L. Stein, Richard Y. Wang, and Frederica P. Perera. 2008. Relation between Cord Blood Mercury Levels and Early Child Development in a World Trade Center Cohort. *Environmental Health Perspectives* 118(8) 1085–1091.

[225] Hisamichi Y, Haraguchi K, Endo T. 2010. "Levels of mercury and organochlorine compounds and stable isotope ratios in three tuna species taken from different regions of Japan." *Environ Sci Technol* 44(15): 5971–8.

[226] Sunderland EM. 2007. "Mercury exposure from domestic and imported estuarine and marine fish in the U.S. seafood market." *Environ Health Perspect.* 115(2): 235–42. Epub 2006 Nov 20.

[227] Mahaffey, K.R., R.P. Clickner and R.A. Jeffries. 2009. Adult Women's Blood Mercury Concentrations Vary Regionally in the U.S.: Association with Patterns of Fish Consumption (NHANES 1999–2004). *Environ. Health Perspect.,* 117: 47–53.

[228] Tran, N.L., L. Barraj, *et al.,* 2004. "Combining food frequency and survey data to quantify long-term dietary exposure: a methyl mercury case study." *Risk Anal* 24(1): 19–30.

[229] *Id.*

[230] Miranda, M.L., S. Edwards, *et al.,* 2011. "Mercury levels in an urban pregnant population in Durham County, North Carolina." *Int J Environ Res Public Health* 8(3): 698–712.

[231] Hightower and Moore, 2003.

[232] Hightower, J.M., A. O'Hare, *et al.,* (2006). "Blood mercury reporting in NHANES: identifying Asian, Pacific Islander, Native American, and multiracial groups." Environ Health Perspect 114(2): 173–175.

[233] McKelvey, W., R.C. Gwynn, *et al.,* 2007. "A biomonitoring study of lead, cadmium, and mercury in the blood of New York city adults." Environ Health Perspect 115(10): 1435–1441.

[234] Hightower*et al.,* 2006.

[235] NAS, 2000.

[236] U.S. EPA, 2001a.

[237] National Institute of Environmental Health Sciences (NIEHS). 1998. Scientific issues relevant to assessment of health effects from exposure to methylmercury. Workshop organized by Committee on Environmental and Natural Resources (CENR) Office of Science and Technology Policy (OSTP), The White House, November 18–20, 1998, Raleigh, NC.

[238] NAS, 2000.

[239] Budtz-Jørgensen, E., N. Keiding, and P. Grandjean. 1999. Benchmark modeling of the Faroese methylmercury data. Final Report to U.S. EPA.

[240] DSHA, 2005.

[241] U.S. EPA. 1986. *Guidelines for the Health Risk Assessment of Chemical Mixtures.* U.S. Environmental Protection Agency, Office of Research and Development, Washington, DC September. EPA/630/R–98/002. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=2256.*

[242] U.S. EPA. 1999. *Guidance for Performing Aggregate Exposure and Risk Assessments.* U.S. Environmental Protection Agency, Office of Pesticide Programs, Washington, DC October. Available at *http://www.pestlaw.com/x/guide/1999/EPA-19991029A.html.*

[243] U.S. EPA. 2000a. *Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures.* U.S. Environmental Protection Agency, Risk Assessment Forum, Washington, DC EPA/630/R–00/002. Available at *http://www.epa.gov/ncea/raf/pdfs/chem_mix/chem_mix_08_2001.pdf.*

[244] U.S. EPA. 2003a. Framework for Cumulative Risk Assessment. Risk Assessment Forum, U.S. Environmental Protection Agency. Washington, DC EPA/630/P–02/001F. EPA/600/P–02/001F. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=54944.*

reflected in the multi-chemical scope of the rulemaking. However, the EPA focused the technical analyses supporting the proposed regulation on effects of individual pollutants rather than cumulative effects.

The EPA disagrees with commenters suggesting that the RfD-based HQ is inappropriate. The SAB "agreed that EPA's calculation of a hazard quotient for each watershed included in the assessment is appropriate as the primary means of expressing risk," and that "because the RfD from which the HQ is calculated is an integrative metric of neurodevelopmental effects of methylmercury, it constitutes a reasonable basis for assessing risk." [245]

The SAB also recommended that EPA revise the Hg Risk TSD to include additional qualitative discussion about uncertainty in the revised Hg Risk TSD. Specifically, the SAB recommended that EPA revise the Hg Risk TSD "to better explain the methods and choices made in the analysis, and analytical results, and where the uncertainties lie." The SAB noted several uncertainties related to the RfD. The EPA agrees with this recommendation and included a more complete discussion of these uncertainties in the revised Hg Risk TSD.

The EPA disagrees that the IQ metric threshold is questionable. The SAB concluded that it was reasonable to consider a loss of >1 or >2 IQ points a public health concern. The SAB stated, "The Panel agreed that if IQ loss is retained in the risk assessment despite these reservations, a loss of one or two points would be an appropriate benchmark." [246] The SAB further comments in their report: "The consensus is that if IQ were to be used, then a loss of 1 or 2 points as a population average is a credible decrement to use for this risk assessment. This metric seems to be derived from the lead literature and was peer reviewed by the Clean Air Scientific Advisory Committee (U.S. EPA CASAC 2007).[247] Although its applicability to methylmercury is questionable, the size of the decrement is justified based on the extensive analyses available from the literature reviewed by CASAC." [248] As noted in other studies,[249] [250] a decrease of 1–2 points at the mean results in a much larger decrease in those with IQs that are much lower or higher than the mean.

Although EPA disagrees that the IQ results are too uncertain to rely upon, the EPA acknowledges that IQ is not the most sensitive neurodevelopmental endpoint affected by MeHg exposure, as also noted by the SAB. The SAB recommended that the IQ analyses be retained but be de-emphasized in the documentation underlying the final regulation. The SAB concluded, "The Panel does not consider it appropriate to use IQ loss in the risk assessment and recommended that this aspect of the analysis be de-emphasized, moving it to an appendix where IQ loss is discussed along with other possible endpoints not included in the primary assessment. While the Panel agreed that the concentration-response function for IQ loss used in the risk assessment is appropriate, and no better alternatives are available, IQ loss is not a sensitive response to methylmercury and its use likely underestimates the impact of reducing methylmercury in water bodies." [251] The EPA is following the SAB's recommendation by deemphasizing the IQ analysis and placing that analysis in an appendix to the revised Hg Risk TSD.

The SAB, however, supported the use of the IQ dose-response function calculated by EPA in the Hg Risk TSD. The SAB noted, "The function used came from a paper by Axelrad and Bellinger (2007) that seeks to define a relationship between methylmercury exposure and IQ. A whitepaper by Bellinger (Bellinger, 2005) [252] describes the sequence of steps in relating methylmercury exposure to maternal hair mercury and then that to IQ. The Mercury Risk TSD furthers notes that IQ has shown utility in describing the health effects of other neurotoxicants. These are appropriate bases for examining a potential impact of reducing methylmercury on IQ, but the SAB does not consider these compelling reasons for using IQ as a primary driver of the risk assessment." [253]

The EPA disagrees that the Agency has overstated or failed to review the scientific literature on cardiovascular effects from MeHg exposure. As summarized in the preamble to the proposal, the EPA stated that the NAS study concluded that "Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.,* neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals." [254] The EPA also stated that additional cardiovascular studies have been published since 2000. The EPA did not develop a quantitative dose response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects, and there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. In the future, the EPA may update the MeHg RfD and will review all of the relevant scientific literature available at that time, including data on all relevant endpoints, and weight of evidence for likelihood that MeHg produces specific effects in humans.

The EPA acknowledges the research regarding the effectiveness of fish advisories. However, the proposed regulation does not address the subject of fish advisories, consumer advice on fish or efficacy of such advice. The EPA rejects the commenter's speculation regarding whether the estimated IQ impacts for the regulation are real. Adverse effects of *in utero* Hg exposure have been reported in populations in the U.S.[255] [256] In another study on neurobehavioral effects of prenatal exposure to MeHg through maternal consumption of seafood, adverse effects are observed for MeHg even without controlling for fish consumption.[257] That study suggests that at normal Japanese dietary intake of MeHg and fish nutrients, the overall effect is adverse. While Japanese fish consumption and Hg exposure are both somewhat higher than the mean U.S. exposure, these levels are still within the distribution of U.S. consumers.

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[245] U.S. EPA–SAB, 2011.

[246] U.S. EPA–SAB, 2011.

[247] U.S. Environmental Protection Agency—Science Advisory Board (U.S. EPA–SAB). 2007. *Clean Air Scientific Advisory Committee's (CASAC) Review of the 1st Draft Lead Staff Paper and Draft Lead Exposure and Risk Assessments.* EPA–CASAC–07–003. March. Available on the internet at *http://yosemite.epa.gov/sab/sabproduct.nsf/989B57DCD436111B852572AC0079DA8A/$File/casac-07-003.pdf.*

[248] U.S. EPA–SAB, 2011.

[249] Axelrad, D. A.; Bellinger, D. C.; Ryan, L. M.; Woodruff, T. J. 2007. "Dose-response relationship of prenatal mercury exposure and IQ: An integrative analysis of epidemiologic data." *Environmental Health Perspectives,* 115, 609–615.

[250] Bellinger DC. 2005. *Neurobehavioral Assessments Conducted in the New Zealand, Faroe Islands, and Seychelles Islands Studies of Methylmercury Neurotoxicity in Children.* Report to the U.S. Environmental Protection Agency. EPA–HQ–OAR–2002–0056–6045.

[251] U.S. EPA–SAB, 2011.

[252] Bellinger, 2005.

[253] U.S. EPA–SAB, 2011.

[254] 76 FR 25001.

[255] Oken *et al.,* 2008.

[256] Lederman *et al.,* 2008.

[257] Suzuki, K., Nakai, K., Sugawara, T., Nakamura, T., Ohba, T., Shimada, M., Hosokawa, T., Okamura, K., Sakai, T., Kurokawa, N., Murata, K., Satoh, C., and Satoh, H. 2007. "Neurobehavioral effects of prenatal exposure to methylmercury and PCBs, and seafood intake: neonatal behavioral assessment scale results of Tohoku study of child development." *Environ Res* 110, 699–704.

Moreover, many studies show that beneficial effects of fish on both cardiovascular and neurodevelopmental health are decreased by concomitant exposure to MeHg. Several studies describe one or more aspects of exposure to fish nutrients and MeHg.[258] [259] [260] [261] [262] [263] [264] Recent studies [265] [266] [267] and analyses indicate the potential for nutrients in fish (particularly marine fish) to mask some of the observed adverse effects of MeHg. Because EPA did not adjust for potential confounding by nutrients in marine fish and mammals, the benchmark doses used in the RfD derivation may be underestimated.

The EPA recognizes the potential for confounding of the effects of Hg on the developing nervous system by a range of nutrients and discusses this uncertainty in the revised Hg Risk TSD. Regarding selenium, the SAB commented that "one SAB member suggests the use of blood markers of selenium-dependent enzyme function, noting that methylmercury irreversibly inhibits selenium-dependent enzymes that are required to support vital-but-vulnerable metabolic pathways in the brain and endocrine system. Impaired selenoenzyme activities would be observed in the blood before they would be observed in brain, but the effect is also expected to be transitory. The use of these measures is a minority view among the SAB members." [268] The SAB did not express a consensus recommendation on adjustments to the risk estimates for exposure to selenium or other nutrients, noting that "there is not enough known about their quantitative impact to support a recommendation of a re-analysis." [269]

6. General Comments on Hg Risk Assessment

Comment: Several commenters generally supported the Hg risk assessment, but several other commenters generally disagreed with the Hg risk assessment. One supporter stated that EPA reasonably determined that Hg emissions pose a public health hazard, correctly requested peer review of Hg risk analysis and correctly concluded EGU-attributable MeHg poses a hazard to public health at watersheds when considering all sources of Hg deposition and U.S. EGUs alone. Two commenters noted that the contribution of U.S. EGUs to total Hg deposition can significantly contribute to hundreds of watersheds, and U.S. EGU deposition alone may endanger sensitive populations near many of these watersheds.

Several commenters claimed that overly conservative assumptions in the risk analysis render the results flawed and unreliable, including using CMAQ to model deposition, Mercury Maps, fish consumption rate and fish MeHg concentrations, overly stringent RFD, national-scale model, using poverty as a surrogate for subsistence fishing, assuming a subsistence fisher resides in most watersheds with fish tissue data, fishers only eat larger fish with high Hg concentrations, cooking loss adjustment, unrealistically high fish ingestion rates (a large fish meal every day), focused on the extremes of the distributions, cast many assumptions as an underestimate of the effect despite evidence to the contrary, and created inappropriate metrics for risk that show no improvement despite significant Hg emissions reductions in the U.S.

Several commenters cite Tetra Tech's analysis that assessed Hg risk using different consumption rates, cooking factor, mean fish tissue concentrations, and EGU-attributable Hg deposition only, which showed considerably fewer watersheds that exceed an HQ of 1 at 2016 deposition levels.

Several commenters claim that this regulation would not significantly reduce Hg exposure via fish consumption because EGU-attributable deposition is a small fraction of total deposition. One commenter stated that EPA's data shows Hg emissions from U.S. EGUs have little influence on fish Hg concentrations despite a reduction of 41 tons of Hg in the U.S. between 2005 and 2016. One commenter requested that EPA accurately describe the low health risks posed by utility hazardous air pollutant emissions. One commenter stated that EPA did not consider scientific information showing that there is no straightforward connection between Hg emissions from U.S. EGUs to the Hg level in fish, which is dependent upon many environmental factors, such as sunlight and organic matter, pH, water temperature, sulfate, bacteria, and zooplankton present in the ecosystem. One commenter stated that there is not any demonstrable evidence that anyone in the U.S. has suffered adverse health problems as a result of Hg emissions from coal-fired EGUs. One commenter stated that EPA's findings are similar to the 2000 findings where EPA found a plausible link between anthropogenic emissions of Hg from sources in the U.S. and MeHg in fish, and "plausible" is a euphemism for unproven.

Several commenters had recommendations for the Hg risk analysis. One commenter stated that more data from Florida should have been included because Florida is known to have a rich data set on fish Hg concentrations. One commenter stated that EPA should characterize general recreational angler fishers instead of subsistence fishers. One commenter claims that EPA made math errors in the Hg Risk TSD regarding the deposition in watersheds at specific percentiles. One commenter questioned EPA's policy metrics used to characterize Hg risk.

Several commenters stated that the Hg TSD is unclear and lacks detail, as noted by the SAB. One commenter stated that the SAB is critical of EPA's efforts, stating that the SAB found it difficult to evaluate the risk assessment based solely upon Hg Risk TSD and recommended that EPA transparently explain the methods and uncertainties. One commenter stated that because of insufficient review time and the lack of detail in the Hg Risk TSD, they could not assess key questions, such as the nation-wide representativeness of the fish tissue data.

One commenter stated the subset of watersheds considered in the analysis (*i.e.*, with fish tissue data) have clearly higher U.S. EGU-attributable deposition than the distribution of all watersheds.

One commenter stated EPA's reporting of IQ point loss is erroneous and not relevant to informing policy, and the U.S. EGU contribution to risk is marginal as evidenced by the null values for the 50th percentile watershed.

One commenter notes that U.S. EGU-attributable emissions of Hg have decreased significantly between 2005

[258] Grandjean P, Bjereve K, Wihe P, and Sterewald u. 2001a. "UBirthweight in a fishing community: significance of essential fatty acids and marine food contaminants." *In. J. Epidemiol.* 30:1272–1278.

[259] Budtz-Jorgensen, E.; Grandjean, P.; Weihe, P. 2007. "Separation of risks and benefits of 16 seafood intake." *Environmental Health Perspectives.* Vol. 115, 323–327.

[260] Choi *et al.*, 2008a.

[261] Choi *et al.*, 2008b.

[262] Oken *et al.*, 2008.

[263] Strain, J.J. *et al.*, 2008. Associations of maternal long chain polyunsaturated fatty acids, methyl mercury, and infant development in the Seychelles Child Development Nutrition Study." *Neurotoxicology.* 29(5): 776–782.

[264] Suzuki, *et al.*, 2007.

[265] Oken *et al.*, 2008.

[266] Choi AL, Cordier S, Weihe P, Grandjean P. 2008a. "Negative confounding in the evaluation of toxicity: the case of methylmercury in fish and seafood." *Crit Rev Toxicol.* 2008;38(10):877–93.

[267] Choi AL, Budtz-Jørgensen E, Jørgensen PJ, Steuerwald U, Debes F, Weihe P, Grandjean P. 2008b. "Selenium as a potential protective factor against mercury developmental neurotoxicity." *Environ Res.* May;107(1):45–52. Epub 2007 Sep 12.

[268] U.S. EPA–SAB, 2011.

[269] *Id.*

and 2016, but claims that this decrease does not appear to affect the risk results.

Response: The purpose of the Hg risk assessment is not to assess the magnitude of risk reduction under the proposed rule, but rather to estimate the magnitude of absolute risk attributable to U.S. EGUs currently and following implementation of other applicable CAA requirements. That said, any potential risk reductions following implementation of the MACT rule itself would likely reflect a number of factors besides the national average U.S. EGU deposition value cited by the commenter. These additional factors include: (a) Spatial gradients in the magnitude of absolute U.S. EGU-attributable Hg deposition, (b) spatial gradients in the magnitude of reductions in Hg deposition linked to the rule, (c) availability of measured fish tissue Hg levels in the vicinity of U.S. EGUs experiencing larger Hg emission reductions to support risk modeling, and (d) the potential for subsistence fishing activity at watersheds in the vicinity of U.S. EGUs experiencing larger reductions in Hg emissions (also required to support risk modeling). It is also important to point out that while the national average U.S. EGU-attributable Hg deposition (for the 2016 scenario—see revised Hg Risk TSD) is two percent, values range up to 11 percent for the 99th percentile watershed. This illustrates the substantial spatial variation in U.S. EGU-attributable Hg deposition, which translates into spatial variation in the magnitude of U.S. EGU-attributable subsistence fisher risk.

The SAB conducted a comprehensive peer review of all of EPA's assumptions in the Hg Risk TSD, and concluded that "the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from Hg emitted from U.S. EGUs." [270] Furthermore, the SAB concluded, "The SAB regards the design of the risk assessment as suitable for its intended purpose, to inform decision-making regarding an "appropriate and necessary finding" for regulation of hazardous air pollutants from coal and oil-fired EGUs, provided that our recommendations are fully considered in the revision of the assessment." [271] Although the SAB did indicate difficulty in evaluating the risk assessment based solely on the Hg Risk TSD, the panel obtained additional information from EPA through the peer review process and determined that "the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs." [272] The primary advice of the SAB panel was that EPA should "revise the Technical Support Document to better explain the methods and choices made in the analysis, and analytical results, and where the uncertainties lie." [273] The EPA has revised the Hg Risk TSD as part of the final rulemaking to address the SAB's recommendations and has made that revised Hg Risk TSD available in the rule docket.

The SAB concurred with EPA's analytical assumptions and overall study design for the Hg Risk TSD, including the RfD-based HQ approach, fish tissue data, 75th percentile size fish, Mercury Maps assumption, and consumption rates. Based on the SAB peer review, the EPA strongly disagrees with commenter statements that the results reported in the Hg Risk TSD are unreliable, overly conservative, extreme, inconsistent with EPA risk guidelines, or severely overstate risk based on the stated objectives of the analysis. The EPA has specifically addressed each of these assumptions in the previous sections of the preamble, and thus, does not repeat those responses here. Based on the review by the SAB, the EPA has accurately described the health risks posed by utility hazardous air pollutant emissions and disagrees with the commenter's statement that EPA has not provided any demonstrable evidence to show that adverse health risks exist. The EPA has applied peer reviewed modeling to estimate the deposition of Hg attributable to U.S. EGUs. The EPA asserts that these metrics demonstrate a clear hazard to public health from Hg emissions from U.S. EGUs.

The EPA thoroughly evaluated the Tetra Tech analysis. The EPA does not agree that the analysis by Tetra Tech uses assumptions that are "more reasonable", and the SAB agreed that all of EPA's assumptions in the Hg Risk TSD are reasonable and appropriate. The EPA asserts that Tetra Tech's analysis does not fully cover subsistence fishers likely to experience elevated U.S. EGU-related Hg exposure. Specifically, the risk estimate cited in the comment reflects application of a number of behavioral assumptions that provide significantly less coverage for higher risk subsistence fishers. Fish consumption surveys cited in the revised Hg Risk TSD suggest that higher percentile subsistence fishers eat more than twice the level of fish assumed by Tetra Tech. Tetra Tech's analysis also used the median fish tissue levels, but it is reasonable to assume that subsistence fishers would target somewhat larger fish to maximize the volume of edible meat per unit time spent fishing. Tetra Tech's analysis also assumed that cooking fish did not concentrate Hg, but a number of studies discussed in the revised Hg Risk TSD explicitly provide adjustment factors involving a higher unit concentration following preparation. Taken together, Tetra Tech's analysis does not address the stated goal of the risk assessment to assess the nature and magnitude of risk for those individuals likely to experience the greatest risk associated with exposure to U.S. EGU-attributable Hg.

The EPA disagrees with the commenter's assertion that this rule will not affect risks associated with Hg exposure. Hg from U.S. EGUs contributes to the levels of MeHg in fish across the country and consumption of contaminated fish can lead to increased risk of adverse health effects. The EPA has shown in the RIA (Chapter 5) that this rule will reduce Hg levels in fish.

The EPA acknowledges that U.S. EGUs contribute only a small fraction of total Hg deposition in the U.S. However, U.S. EGUs remain the largest emitter of Hg in the U.S., and the revised Hg Risk TSD shows that U.S. EGU-attributable Hg deposition results in up to 29 percent of modeled watersheds with populations potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. Mercury risk is increasing for exposures above the RfD, and as a result, any reductions in Hg exposures in locations where total exposures exceed the RfD can result in reduced risks. While these reductions in risk may be small for most populations and locations, in some watersheds and for some populations, reductions in risk may be greater.

The SAB also directly addressed the question of the nation-wide representativeness of the fish tissue MeHg data in the national Hg risk assessment. The SAB concluded, "Although the SAB considers the number of watersheds included in the assessment adequate, some watersheds

[270] U.S. EPA–SAB, 2011.

[271] *Id.*

[272] *Id.*

[273] *Id.*

in areas with relatively high mercury deposition from U.S. EGUs were under-sampled due to lack of fish tissue methy[l]mercury data. The SAB encourages the Agency to contact states with these watersheds to determine if additional fish tissue methylmercury data are available to improve coverage of the assessment." [274] In response to the SAB's recommendations, the EPA obtained additional fish tissue sample data from several states, particularly Pennsylvania, Wisconsin, Minnesota, New Jersey, and Michigan. This additional data increased the total number of watersheds assessed in the analysis by 33 percent nationally. In Florida, the EPA assessed the Hg-related health risk for 40 watersheds. Because EPA did not find any additional fish tissue data for watersheds in Florida that could be incorporated into the analysis, the total number of watersheds in Florida assessed in the revised Hg Risk TSD remains the same as the Hg Risk TSD at proposal.

The EPA disagrees with the commenter that there were errors in the Hg Risk TSD. Instead, the commenter has misinterpreted how EPA calculated the percentiles. The percentile (and mean) values presented in Table ES–1 for total and U.S. EGU-attributable Hg deposition are not matched by watershed. In other words, the EPA queried for the percentiles (and mean) provided for total Hg deposition and presented those percentiles and then separately estimated the percentiles for U.S. EGU-attributable Hg. Therefore, the total and U.S. EGU-attributable values for the 99th percentile do not necessarily occur at the same watershed. The EPA has provided additional clarification in the revised Hg Risk TSD.

The EPA agrees with the commenter that MeHg levels in fish depend on a complicated set of environmental factors, and EPA acknowledged this in the revised Hg Risk TSD. Furthermore, the EPA acknowledges that total Hg fish tissue levels are not correlated with levels of total Hg deposition when looking across watersheds because this relationship is highly dependent on the methylation potential at the specific waterbody, which is affected by pH, sulfate deposition, turbidity, etc. However, several recent studies [275] [276] [277] show, and the SAB agrees, that it is appropriate for EPA to assume that changes in Hg deposition are linearly associated with *changes* in fish tissue concentration. In addition, the EPA agrees that the subset of watersheds in the risk analysis have somewhat higher U.S. EGU deposition than the distribution of all watersheds, but EPA disagrees that oversampling of high deposition watersheds is inappropriate.

The EPA does not agree that there is no improvement in fish Hg concentrations between 2005 and 2016, or that there will be no further improvement from decreasing Hg emissions from U.S. EGUs from the baseline in 2016. Although total risk from all Hg exposures will remain elevated in much of the U.S., much of that risk is associated with global, non-U.S. Hg emissions. U.S. EGUs remain the largest source of Hg emissions in the U.S., and reductions in those emissions will result in reduced Hg deposition in many highly impacted watersheds. As shown in the revised Hg Risk TSD, average U.S. EGU-attributable fish tissue Hg concentrations is estimated to decrease by 44 percent between 2005 and 2016. Although we did not remodel risk for the 2005 scenario in the revised Hg Risk TSD, we estimated at proposal that the total percent of modeled watersheds with populations potentially at-risk from Hg emissions from U.S. EGUs exceeding either risk metric (*i.e.*, U.S. EGUs alone or total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent) would decline from 62 percent in 2005 to 28 percent in 2016. This projected decline is primarily due to a combination of additional pollution control technologies installed to comply with federal regulations, such as CSAPR, and changing fuels, such as the shift to natural gas.

The EPA disagrees that IQ loss is erroneous or irrelevant to informing policy, but EPA has moved that analysis to an appendix in the revised Hg Risk TSD, per the SAB's recommendation. The EPA disagrees that the IQ effects at the 50th percentile watershed are useful in determining that there is not a hazard to public health because EPA's stated goal of the risk assessment was to focus on populations likely to experience relatively higher exposures to U.S. EGU-attributable Hg.

We also disagree with those commenters that point to the SAB's statements concerning the clarity of the Hg Risk TSD to suggest that the public did not have an ample opportunity to comment on the Hg risk assessment. Although it is correct that the SAB said the Hg Risk TSD was difficult to evaluate until EPA staff explained it at the public meeting in June 2011, we note that the commenters that assert that this issue amounts to a violation of CAA section 307(d) notice requirements made detailed technical comments, including many of the same comments as the SAB. Furthermore, the EPA provided notice of the peer review in the preamble to the proposed rule and a number of **Federal Register** notices advised the public of the peer review process and all the meetings were open to the public for comment and participation and the minutes of those meetings were posted on the SAB Web site. The minutes for the June 2011 meeting, during which EPA provided clarifying information, were available well within the public comment period for the proposed rule. For these reasons, we maintain that the public was provided an adequate opportunity to comment on the Hg risk assessment.

e. Non-Hg HAP Case Studies

1. Emissions for Non-Hg Case Studies

Comment: The commenters raised concerns about a wide variety of aspects of EPA's approach for emissions used for the non-Hg case studies, including the use of an arithmetic mean for computing emission factors for representing emissions of untested units, the suggestion of statistical outliers in the Cr test data, the claim that metals content of the fuel is an indicator of flawed test data, the statistical approaches used by EPA to create emission factors, the absence in EPA's approach of an equation that commenters claim better represents emissions values, that EPA's approach to estimate Cr(VI) is flawed, and the lack of coal rank as a delineating factor for emission factor calculation. The commenters also suggested that EPA should revise stack parameters used for the case studies based on better available data.

Response: In response to the comments on the emission factors, the EPA has undertaken additional analysis to address all commenter concerns. The EPA disagrees with commenter's criticisms of emission factors based on arithmetic means, and EPA demonstrates that the use of an arithmetic mean provides the most representative result. The EPA analysis has found that the geometric mean approach recommended by the commenter always under predicts actual emissions by an average of more than seventy percent. The EPA agrees with commenters' recommendations to use statistical outlier tests, but has applied tests different from those suggested by the commenters. As further explained in the response to comments document in the docket, this approach did not eliminate the Cr test data from the Cr

[274] U.S. EPA–SAB, 2011.
[275] Orihel *et al.*, 2007.
[276] Orihel *et al.*, 2008.
[277] Harris *et al.*, 2007.

emission factors used for some of the case study emissions.

The EPA disagrees with commenters' assertions that the metal content of the coal is a basis for invalidating the test results of high Cr emissions. The identification of sources whose measured emissions do not match the commenters' preconceived idea of emissions behavior is not surprising. There are many possible explanations for these differences. For example, the inconsistency between the test data and the coal analysis could be due to any number of reasons including unrepresentative coal sampling, control device problems, degradation of the refractory, or sampling contamination. The idea that test data should be discarded because it does not match initial expectations is unfounded.

The EPA disagrees with the commenter recommendations for using an equation from AP–42, developed in part by the commenters. Based on analyses of metal emissions measured at the site compared to statistically predicted estimates, the EPA concluded that measured emissions test data better predict actual emissions, and emission factors based on the arithmetic mean are a reasonable method to estimate emissions when test data are not available. The EPA analysis of the ICR data has found that the emissions equation recommended by the commenter is not a good predictor of actual EGU emissions. The EPA also disagrees with commenters' concerns about the assumption that 12 percent of the Cr will be Cr(VI) for every coal-fired unit, which was specifically supported by the peer review on the approach for estimating cancer risks associated with Cr and Ni emissions. The EPA disagrees with the commenter's assertion that any impact of scrubbers will impact the case study analyses. In EPA's revised case study analysis, 6 facilities have risk greater than 1 in a million, and of these, four facilities have Cr as the risk driver (James River, Conesville, TVA Gallatin, and Dominion—Chesapeake Bay). For these facilities, none of the units contributing the bulk of the Cr emissions have scrubbers according to the data provided to EPA by those facilities, so scrubber impacts on Cr speciation is not relevant to EPA's conclusions based on the non-Hg case studies. In any case, the EPA disagrees with the commenter's conclusions about the impacts of scrubbers on Cr speciation and provides evidence that impacts of scrubbers on Cr speciation can have the opposite effect on Cr(VI) fractions, concluding that EPA's 12 percent assumption is somewhat conservative.

The EPA also disagrees that coal rank must be a factor in computing Cr emission factors for use in the case studies. The EPA's analysis has demonstrated that coal rank appears to play no role in non-Hg metals emissions. The EPA's newly revised emissions factor development procedures can isolate and compare subgroups based on control device type or coal rank; the ICR data were subjected to these tests and no statistical significance was found between coal rank groups.

Finally, the EPA agrees with one commenter's recommendations on revised stack parameters for the case studies and has included these revisions in the case study modeling for the final rule.

2. General Comments on Non-Hg Risk Case Study

Comment: One commenter stated that EPA's case study assessment reaffirms the need to regulate HAP emitted by both coal and oil-fired EGUs. The commenter noted that over 40 percent of the case studies conducted by EPA to quantify health hazards associated with the inhalation of non-Hg HAP indicated a cancer risk greater than or equal to the one in a million threshold level required to delist a source category under CAA section 112.

One commenter stated that EPA's case study assessment might be flawed by the use of "beta" tests versions of the AERMOD meteorological preprocessors (AERMINUTE and AERMET). The commenter obtained from EPA the meteorological data used for EPA's assessment of the Conesville facility and processed these data with EPA's current regulatory versions of these preprocessors, which differ from the beta version. According to the commenter, a comparison of the hourly wind speed and hourly wind direction data produced by the beta preprocessor and by current EPA preprocessors revealed numerous and often substantial disparities.

One commenter stated that EPA's finding that only three coal-fired facilities and one oil-fired facility out of roughly 440 coal-fired facilities and 97 oil-fired facilities in the U.S. indicated risk greater than one-in-a-million supports a finding that it is "appropriate" to regulate those four and not the other 537. Another commenter stated that EPA found only a "few" facilities that have estimated maximum cancer risks in excess of one in a million, and that this does not justify regulating all non-Hg HAP for all sources in this category.

One commenter stated that EPA's discussion in the preamble to the proposed rule misleads the reader into believing that non-Hg HAP emissions from EGUs are associated with serious human health effects. According to the commenter, the EPA's discussion of the effects associated with excessive exposure to an individual HAP would lead the reader to believe that those effects inevitably occur from EGU emissions because EGU emissions have trace amounts of non-Hg HAP.

One commenter stated that with the assumptions in the Utility Study, both in terms of conservative scientific estimates and overestimated amounts of oil burned by these units, the EPA concluded that the risks from oil-fired units would result in only one new cancer case every 5 years. The commenter does not believe that this level of risk warrants regulation under CAA section 112(n)(1)(A).

Several commenters stated that even if the additional studies EPA performed were accurate, they hardly demonstrate that it is necessary and appropriate to regulate coal-fired EGU HAP under CAA section 112 because three sites nationwide show risks greater than one in a million, with the highest at eight in a million.

One commenter stated that the highest cancer risk estimated for coal-fired EGUs is still within the acceptable range used by EPA in other programs and is also far less than the background exposure risks the average person experiences. The background risk of developing cancer in a lifetime is approximately one in three (0.33). According to EPA's own data, the predicted added cancer risk of exposure to HAP from U.S. EGUs would change the background risk from 0.33 to 0.330001. This level of change is so minimal that it could not be observed in any health effects study that might be conducted.

One commenter stated that EPA conducted a health risk assessment on a limited number of facilities and found a "few" facilities that have estimated maximum cancer risks in excess of one in a million. The commenter stated that, based on this limited health risk assessment, the EPA apparently decided that they were justified to regulate all non-Hg HAP for all sources in this category.

Several commenters stated that EPA's assumption implies that a person stays exactly at the center of a census tract for 70 years and that a unit will operate in exactly the same manner for 70 years is unrealistic. The commenters suggest that Tier 3 risk assessment is warranted

or a lifetime exposure adjustment is needed.

One commenter asserts that because the alleged health benefits are derived from total exposure, the EPA should explain how its numerical emission limit units, which would not directly restrict total exposure if heat inputs increase, redress this health concern. In its preamble, the EPA simply notes that its emission limit units are consistent with, and allow for simple comparison to, other regulations.

One commenter questioned whether acid gas emissions limits for oil-fired units are "appropriate" or "necessary" because EPA's new technical analyses do not indicate a health concern from acid gas emissions from oil-fired units. According to the commenter, the EPA identifies Ni as the main HAP of concern from oil-fired units, even though cancer-related inhalation risks were well below the RfCs and EPA states that significant uncertainty remains as to whether those emissions present a health concern.

Response: The EPA agrees with the commenter that the non-Hg HAP risk assessment confirms the appropriate and necessary finding.

The EPA disagrees that EPA's case study assessment is flawed by the use of beta versions of AERMINUTE and AERMET. The EPA remodeled the case study facilities using the current versions of AERMINUTE (version 11059), AERMET (version 11059), and AERMOD (version 11103). Although there were differences in the number of calm and missing winds in the current AERMINUTE/AERMET output compared to the beta version, the resulting risks differed by less than two percent, on average. For Conesville, which had the largest difference in calms between the beta and current versions of AERMINUTE/AERMET, the risks differed by three percent. For the final rule, the case study facilities have been modeled with the current available versions of AERMINUTE, AERMET, and AERMOD.

The EPA disagrees with the commenter that having only a few case study facilities exceeding one in a million risk invalidates the "appropriate finding". The 16 facilities EPA selected as case studies for assessment may not represent the highest-emitting or highest-risk sources. Although case study facility selection criteria included high estimated cancer and non-cancer risks using the 2005 NEI data, high throughput, and minimal emission control, another necessary criterion was the availability of Information Collection Request (ICR) data for the EGUs at those facilities (or for similar EGUs at other facilities). Because the ICR data were collected for the purpose of developing the MACT standards, the ICR was targeted towards better performing sources for non-Hg metal HAP, acid gas HAP, and organic HAP, with a smaller set of random recipients. Therefore, facilities for which ICR data were available may not represent the highest-emitting sources. The EPA's assessment of the case study facilities for the proposed rule concluded that three coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million. For the final rule, revisions were made to the 16 case studies based on comments received, and the results indicate that 5 coal-fired facilities and 1 oil-fired facility had estimated lifetime cancer risks greater than 1 in a million. The EPA maintains that its finding that more than 30 percent of the case study facilities had a cancer risk greater than one in a million is sufficient to support the appropriate finding.

The EPA disagrees with the commenter's assertion that the health effects associated with exposures to non-Hg HAP from U.S. EGUs are mischaracterized in the preamble to the proposed rule. The discussion of the health effects of non-Hg HAP provided in the preamble includes general information on the potential health effects associated with a broad range of exposure concentrations (from low to high levels) of the various non-Hg HAP (some of which have been determined to be carcinogenic to humans) based on peer reviewed scientific information extracted from priority sources such as IRIS, Cal EPA and ATSDR health effects assessments.

The EPA disagrees with the commenter's characterization of the Utility Study. The Utility Study represented the highest-quality factual record of information available at the time regarding EGU emissions and risks. Further, the EPA's revised risk assessments of 16 case studies, performed with more recent data and refined scientific methods, indicate that there are six U.S. EGU facilities that pose estimated inhalation cancer risks greater than 1 in a million. The EPA maintains that the findings of the case studies are one element that independently supports our determination that it remains appropriate and necessary to regulate EGUs under CAA section 112.

The EPA does not agree with the commenter who suggested that EPA should interpret the results of the non-Hg HAP risk analysis in the context of background cancer risk. As explained in the preamble to the proposed rule, the EPA reasonably looked to the cancer risk threshold established under CAA section 112(c)(9)(B)(1) for delisting a source category as an indicator of the level of cancer risk that was appropriate to regulate under CAA section 112. The commenters comparison of the cancer risk from EGUs as compared with the risk of contracting cancer from unknown sources is not the standard Congress established for evaluating HAP emission risk and the commenter has provided no support for its contention that the Agency should evaluate risk in that manner. The EPA maintains that the analysis was reasonable.

The EPA does not agree with the commenter's implication that EPA must make a facility-specific finding for each HAP for each source and then only regulate individual EGU facilities for the individual HAP that identified as causing an identified hazard to public health or the environment. That approach is not required under CAA section 112(n)(1) or anywhere under CAA section 112, and it would be virtually impossible to undertake such an effort. For these reasons, the EPA does not agree with the commenter and maintains that the appropriate and necessary finding is reasonably supported by the record and consistent with the statute for all the reasons set forth in the preamble to the proposed rule and this final action.

The EPA disagrees that an exposure adjustment is needed to account for conditions changing over 70 years because it runs counter to the long-standing approach that EPA has taken to estimate the maximum individual risk, or MIR. The MIR is defined by EPA's Benzene NESHAP regulation of 1989[278] and codified by CAA section 112(f) as the lifetime risk for a person located at the site of maximum exposure 24 hours a day, 365 days a year for 70 years (*e.g.*, census block centroids). The MIR is the metric associated with the determination of whether or not a source category may be delisted from regulatory consideration under CAA section 112(c)(9). The MIR is the risk metric used to characterize the inhalation cancer risks associated with the case study facilities. The EPA used the annual average ambient air concentration of each HAP at each census block centroid as a surrogate for the lifetime inhalation exposure concentration of all the people who reside in the census block. The EPA has used this approach to estimate MIR values in all of its risk assessments to

[278] 54 FR 38044.

support risk-based rulemakings under CAA section 112 to date.

The EPA disagrees with the commenter's assertion that the numerical emission limits being promulgated in today's final rule must be justified on their ability to redress the health concerns that were identified as the basis for regulating EGUs. The emission limits in today's rule are technology-based, as prescribed under CAA section 112, and do not need to be justified based on their ability to protect public health. Regarding potential health concerns, the EPA has up to 8 years after the promulgation of the technology-based emission limits for EGUs to determine whether the regulations protect public health with an ample margin of safety. If the regulations do not, the CAA directs EPA to promulgate additional more stringent standards (within the prescribed 8 years) to achieve the appropriate level of public health protection.

Furthermore, the EPA reasonably concluded that it was appropriate and necessary to regulate oil-fired EGUs in 2000, and EPA confirmed that conclusion was proper with the analysis set forth in the preamble to the proposed rule. Certain commenters question the determination based on their views of how the Agency can and should exercise its discretion. The EPA disagrees with these commenters and stands by the determination for the reasons set forth in the preamble to the proposed rule. The EPA also stands by the determination that the maximum cancer risks posed by emissions of oil-fired EGUs are greater than one in a million, due primarily to emissions of Ni compounds. Based on our analysis, we are unable to delist oil-fired EGUs.

3. Ni Risk

Comment: Several commenters stated that the assumptions regarding the speciation and carcinogenic potential of Ni compounds used in EPA's inhalation risk assessment of the case study facilities are overly conservative and likely to overstate the risks. With respect to Ni speciation, the commenters stated that there are substantial uncertainties regarding the species of Ni being emitted and the risk of such emissions, and that EPA has made ultraconservative assumptions aimed at overestimating the risk. The commenters stated that assigning the same carcinogenic potency of Ni subsulfide to other forms of Ni is overly conservative and inconsistent with the best available evidence.

Response: The EPA disagrees with the commenters' assertion that it is impossible to give an accurate assessment of the risks to human health from Ni emissions from EGUs, and maintains that its assessment of the potential inhalation risks from EGU emissions of Ni compounds is scientifically valid, reasonable, and based on the best-available current scientific understanding. To that end, in July 2011, the EPA completed an external peer review (using three independent expert reviewers) of the methods used to evaluate the risks from Ni and Cr compounds emitted by EGUs.[279] There were two charge questions relating to Ni in that review. First, do EPA's judgments related to speciated Ni emissions adequately take into account available speciation data, including recent industry spectrometry studies? Second, based on the speciation information available and what is known about the health effects of Ni compounds, and taking into account the existing URE values (*i.e.*, values derived by the Integrated Risk Information System,[280] California Department of Health Services,[281] and the Texas Commission on Environmental Quality [282]), which of the following approaches to derive unit risk estimates would result in a more accurate and defensible characterization of risks from exposure to Ni compounds?

1. To continue using the same approach as that developed for use in the 2000 NATA, which consists of using the IRIS URE for nickel subsulfide and assuming that nickel subsulfide constitutes 65 percent of the mass emissions of all Ni compounds.

2. To consider a more health-protective approach, based on the consistent views of the most authoritative scientific bodies (*i.e.*, NTP in their 12th ROC, IARC, and other international agencies) that consider Ni compounds to be carcinogenic as a group.

3. To make the same assumptions as in option 2, but considering alternative UREs derived by the CDHS or TCEQ.

In responding to these peer review questions, two of the reviewers agreed with the views of the most authoritative scientific bodies, which consider Ni compounds carcinogenic as a group. These reviewers, therefore, did not focus on the availability of Ni speciation profile data. The third reviewer recommended that EPA review several manuscripts on Ni speciation profiles showing that sulfidic Ni compounds (which the reviewer considered as the most potent carcinogens) are present at low levels in emissions from EGUs.

Nickel and Ni compounds have been classified as human carcinogens by national and international scientific bodies including the IARC,[283] the World Health Organization,[284] and the European Union's Scientific Committee on Health and Environmental Risks.[285] In their *12th Report of the Carcinogens,* the NTP has classified Ni compounds as known to be human carcinogens based on sufficient evidence of carcinogenicity from studies in humans showing associations between exposure to Ni compounds and cancer, and supporting animal and mechanistic data. More specifically, this classification is based on consistent findings of increased risk of cancer in exposed workers, and supporting evidence from experimental animals that shows that exposure to an assortment of Ni compounds by multiple routes causes malignant tumors at various organ sites and in multiple species. The *12th Report of the Carcinogens* states that the "combined results of epidemiological studies, mechanistic studies, and carcinogenesis studies in rodents support the concept that Ni compounds generate Ni ions in target cells at sites critical for carcinogenesis, thus allowing consideration and evaluation of these compounds as a single group".[286] Although the precise Ni compound (or compounds) responsible for the carcinogenic effects in humans is not always clear, studies indicate that Ni sulfate and the combinations of Ni sulfides and oxides encountered in the Ni refining industries cause cancer in humans. There have been different views on whether or not Ni compounds, as a group, should be considered as carcinogenic to humans. Some authors

[279] U.S. EPA, 2011c.

[280] *U.S.* EPA, 1991.

[281] California Department of Health Services (CDHS) 1991. Health Risk Assessment for Nickel. Air Toxicology and Epidemiology Section, Berkeley, CA. Available online at *http://oehha.ca.gov/air/toxic_contaminants/html/Nickel.htm.*

[282] Texas Commission on Environmental Quality (TCEQ), 2011. Development Support Document for nickel and inorganic nickel compounds. Available online at *http://www.tceq.state.tx.us/assets/public/implementation/tox/dsd/final/june11/nickel_&_compounds.pdf.*

[283] International Agency for Research on Cancer (IARC), 1990. IARC monographs on the evaluation of carcinogenic risks to humans. *Chromium, nickel and welding.* Vol. 49. Lyons, France: International Agency for Research on Cancer, World Health Organization Vol. 49:256.

[284] International Labour Organization/United Nations Environment Programme, World Health Organization (WHO), 1991. Nickel. In Environmental Health Criteria No 108 Geneva.

[285] European Commission, Scientific Committee on Health and Environmental Risks (SCHER), 2006. Opinion on: Reports on Nickel, Human Health part. SCHER, 11th plenary meeting of 04 May 2006 *http://ec.europa.eu/health/ph_risk/committees/04_scher/docs/scher_o_034.pdf.*

[286] NTP, 2011.

believe that water soluble Ni, such as Ni sulfate, should not be considered a human carcinogen, based primarily on a negative Ni sulfate 2-year NTP rodent bioassay (which is different than the positive 2-year NTP bioassay for Ni subsulfide).[287] [288] [289] Although these authors agree that the epidemiological data clearly supports an association between Ni and increased cancer risk, they sustain that the data are weakest regarding water soluble Ni. A recent review[290] highlights the robustness and consistency of the epidemiological evidence across several decades showing associations between exposure to Ni and Ni compounds (including Ni sulfate) and cancer.

Based on the views of the major scientific bodies mentioned above, and those of expert peer reviewers that commented on EPA's approaches to risk characterization of Ni compounds, the EPA considers all Ni compounds to be carcinogenic as a group and does not consider Ni speciation or Ni solubility to be strong determinants of Ni carcinogenicity. With regards to non-cancer effects, comparative quantitative analysis across Ni compounds indicates that Ni sulfate is as toxic or more toxic than Ni subsulfide or Ni oxide.[291] [292]

Regarding the second charge question, two of the reviewers suggested using the URE derived by TCEQ for all Ni compounds as a group, rather than the one derived by IRIS specifically for Ni subsulfide. The third reviewer did not comment on alternative approaches. The EPA decided to continue using 100 percent of the current IRIS URE for Ni subsulfide because IRIS values are at the top of the hierarchy with respect to the dose response information used in EPA's risk characterizations, and because of the concerns about the potential carcinogenicity of all forms of Ni raised by the major national and international scientific bodies. Nevertheless, taking into account that there are potential differences in toxicity and/or carcinogenic potential across the different Ni compounds, and given that there have been two URE values derived for exposure to mixtures of Ni compounds that are 2–3 fold lower than the IRIS URE for Ni subsulfide, the EPA also considers it reasonable to use a value that is 50 percent of the IRIS URE for Ni subsulfide for providing an estimate of the lower end of a plausible range of cancer potency values for different mixtures of Ni compounds.

4. Cr Risk

Comment: One commenter stated there are several problems with EPA's analysis related to the fact that Cr emissions were evaluated as being entirely Cr(VI). The commenter stated that not all of the emitted Cr will remain in the hexavalent form by the time it reaches the target population, and that some may be converted to the much less toxic (and noncarcinogenic) trivalent species. The commenter also stated that the concentration levels considered in the case study assessment are far below occupational levels. The commenter concluded that EPA's cancer estimates should, therefore, be looked on with some skepticism. Another commenter stated that EPA's estimate of 12 percent Cr(VI) from coal-fired EGUs is unsupported, and that EPA failed to recognize that Cr(VI) is highly water-soluble and is easily reduced to Cr(III) in the presence of SO_2 in a low pH environment. The resulting Cr(III) would be expected to precipitate out in a FGD. The commenter stated that the actual amount of Cr(VI) that would be present in the emissions from an EGU with a wet scrubber is likely to be far lower than the 12 percent estimate made by EPA.

Several commenters questioned the validity of the chronic inhalation study by EPA because of (1) the use of surrogate speciated Cr emissions data instead of actual emissions data, (2) the assumption that units were run 100 percent of the time which is impossible, (3) dispersion modeling was used that is biased towards over predicting downwind impacts, and (4) estimated ambient concentrations were utilized as substitutes for real exposure concentrations for all people within a census block.

Response: The EPA disagrees with the commenters' assertion that all Cr was considered to be hexavalent. As discussed in "Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds," [293] existing test data for utility and industrial boilers indicate that Cr(VI) is, on average, 12 percent of total Cr from coal-fired boilers. This document underwent peer review by three external reviewers, and all three reviewers considered EPA's use of the values to be reasonable given the limited data available for Cr speciation profiling. The EPRI inhalation study for coal-fired boilers also used the 12 percent value.

The EPA also disagrees that units were assumed to operate 100 percent of the time. The dispersion modeling performed for the case study facilities used hourly heat input as a temporalization factor for estimating hourly emissions, and in some cases hourly heat inputs (and emissions) were zero or very low. The commenter provided no data or information to support their claim that the dispersion modeling EPA used is biased towards overestimating downwind impacts.

The EPA disagrees with the commenters' assertion that "real exposure concentrations for all people within a census block" must be considered because it runs counter to the long-standing approach that EPA has taken to estimate the maximum individual risk, or MIR. The MIR is defined by EPA's Benzene NESHAP regulation of 1989 [294] and codified by CAA section 112(f) as the lifetime risk for a person located at the site of maximum exposure 24 hours a day, 365 days a year for 70 years (*e.g.*, census block centroids). The MIR is the metric associated with the determination of whether or not a source category may be delisted from regulatory consideration under CAA section 112(c)(9). The MIR is the risk metric used to characterize the inhalation cancer risks associated with the case study facilities. The EPA used the annual average ambient air concentration of each HAP at each census block centroid as a surrogate for the lifetime inhalation exposure concentration of all the people who reside in the census block. The EPA has used this approach to estimate MIR values in all of its risk assessments to support risk-based rulemakings under CAA section 112 to date.

5. Acid Gas Risk

Comment: One commenter stated that acid gas emissions from oil-fired EGUs are not of the magnitude that triggered EPA's decision to regulate EGUs in general, raising the question of whether reduction (or even total elimination) of acid gas emissions from oil-fired EGUs could have any significant effect on EPA's goals of reducing non-cancer

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[287] Oller A. Respiratory carcinogenicity assessment of soluble nickel compounds. Environ Health Perspect. 2002, 110:841–844.

[288] Heller JG, Thornhill PG, Conard BR. New views on the hypothesis of respiratory cancer risk from soluble nickel exposure; and reconsideration of this risk's historical sources in nickel refineries. J Occup Med Toxicol. 2009, 4:23.

[289] Goodman JE, Prueitt RL, Thakali S, and Oller AR. The nickel iron bioavailability model of the carcinogenic potential of nickel-containing substances in the lung. Crit Rev Toxicol. 2011, 41:142–174.

[290] Grimsrud TK and Andersen A. Evidence of carcinogenicity in humans of water-soluble nickel salts. J Occup Med Toxicol. 2010. 5:1–7. Available online at *http://www.ossup-med.com/content/5/1/7.*

[291] Haber LT, Allen BC, Kimmel CA. Non-Cancer Risk Assessment for Nickel Compounds: Issues Associated with Dose-Response Modeling of Inhalation and Oral Exposures. Toxicol Sci. 1998. 43:213–229.

[292] NTP, 1996.

[293] U.S. EPA, 2011c.

[294] 54 FR 3804.

health risk or acidification of sensitive ecosystems in the U.S.

Several commenters stated that acid gas concentrations estimated in the case study facility assessment and the Utility Study do not exceed human health thresholds of concern. Two commenters stated that HCl emissions are negligible compared to other primary emissions (such as SO_2) that can lead to potential acidification of ecosystems.

Response: We do not agree with commenter's implication that Congress intended EPA to regulate only those HAP emissions from U.S. EGUs for which an appropriate and necessary finding is made, and commenter has cited no provision of the statute that states a contrary position. The EPA concluded that we must find it "appropriate" to regulate EGUs under CAA section 112 if we determine that a single HAP emitted from EGUs poses a hazard to public health or the environment. If we also find that regulation is necessary, the Agency is authorized to list EGUs pursuant to CAA section 112(c) because listing is the logical first step in regulating source categories that satisfy the statutory criteria for listing under the statutory framework of CAA section 112. *See New Jersey,* 517 F.3d at 582 (stating that "[s]ection 112(n)(1) governs how the Administrator decides whether to list EGUs * * *"). As we noted in the preamble to the proposed rule, D.C. Circuit precedent requires the Agency to regulate all HAP from major sources of HAP emissions once a source category is added to the list of categories under CAA section 112(c). *National Lime Ass'n* v. *EPA,* 233 F.3d 625, 633 (D.C. Cir. 2000). 76 FR 24989. The EPA discusses in the preamble to the proposed rule and this final action its concerns with HCl and other acid gas HAP emissions from EGUs and the Agency's approach for establishing section 112(d) standards for acid gas HAP.

6. EPRI Risk Analysis

Comment: Two commenters stated that a comprehensive tiered inhalation risk assessment (the EPRI study) using EPA-prescribed methods with improved emission factors, fuel data, and confirmed stack parameters did not identify significant health risks (cancer or non-cancer) among U.S. coal-fired power plants (as they existed in 2007). The commenters noted that these results contrast with those presented by EPA for its non-Hg case studies on 16 (15 coal-fired) power plants. The commenters stated that several issues appear to underlie these differences, indicating the need for EPA to reevaluate its assessment and to undertake more refined (Tier 3) risk assessment for any facility of concern. Several commenters stated that for non-Hg HAP EPA produced one study on chronic inhalation risk assessment that identified three sites with cancer risks greater that one in a million for Cr(VI), which was authored by EPA staff and not peer reviewed. One commenter stated that EPA study is based on misinformation and overestimates assumptions, and that EPA has no data demonstrating health impacts from EGU emissions of non-Hg HAP, or the benefit from reducing such emissions. Two commenters stated that no benefits will be derived from the non-Hg HAP emission reductions associated with the proposed rule because no non-Hg HAP health risks were proven, and that no showing was made that EGU non-Hg HAP emission levels reach levels associated with adverse health effects. Another commenter stated that EPA must complete a comparable and separate national-scale risk assessment for non-Hg metals in order to determine appropriateness of proposing emissions standards for non-Hg metals.

Response: The commenters are incorrect in the assertion that EPA's case studies were performed with less rigor than the EPRI analysis. The EPRI analysis used a tiered approach to risk assessment, beginning with Tier 1 using EPA's SCREEN3 dispersion model on all 470 coal-fired power plants in the U.S., and following with Tier 2 with EPA's Human Exposure Model (which uses the AERMOD dispersion model) for plants with higher risks from the Tier 1 modeling. Although tiered risk assessment is an appropriate approach, the Tier 2 modeling could have been more refined. For example, more meteorological data could have been used and building downwash could have been considered. The EPRI analysis ostensibly concluded that the Tier 2 modeling with HEM was conservative, and that because the modeled risks did not exceed certain thresholds, no further refinement was necessary. However, such refinements could result in higher modeled risks than those from the commenter's Tier 2 modeling.

The EPA's dispersion modeling of the case study facilities was actually performed with a greater degree of refinement than the EPRI analysis, and was consistent with EPA's *Guideline on Air Quality Models.*[295]

In contrast to the approach used in the EPRI analysis, the EPA used:

(1) 5 years of recent meteorological data from the weather station nearest to each facility, rather than one year of meteorological data. This is more representative of long-term (*i.e.,* lifetime) exposures and risks.

(2) Temporally-varying emissions based on continuous emissions monitoring data, rather than assuming a constant emission rate for each facility throughout the entire simulation.

(3) Building downwash, where appropriate.

(4) The latest version of AERMOD [version 11103].

The EPA's assessment of the case study facilities for the proposed rule concluded that three coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million. For the final rule, revisions were made to the case studies based on comments received, and the results indicate that five coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million.

Regarding peer review, the risk assessment methodology used by EPA for the case studies was consistent with the method that EPA uses for assessments performed for Risk and Technology Review rulemakings, which underwent peer review by the Science Advisory Board in 2009.[296] The SAB issued its peer review report in May 2010. The report generally endorsed the risk assessment methodologies used in the program. In addition, in July 2011, the EPA completed a letter peer review of the methods used to develop inhalation cancer risk estimates for Cr and Ni compounds.

f. Ecosystem Impacts From HAP

Comment: Two commenters assert that EPA is not justified in regulating acid gases based on concern about the potential that acid gases contribute to ecosystem acidification rather than concerns about hazards to public health. The commenters further claim that HCl's contribution to ecosystem acidification is de minimis. The commenters point out that EPA acknowledges uncertainty in quantification of acidification and EPA relies on recently published research[297] that is irrelevant to the question since it is based on research conducted in the peat bog ecosystem in the United Kingdom. Another commenter calls attention to several new studies published in a special issue of the

[295] Appendix W to 40 CFR Part 51.

[296] U.S. EPA–SAB, 2010.

[297] Evans, Chris D., Don T. Monteith, David Fowler, J. Neil Cape, and Susan Brayshaw. 2011. "Hydrochloric Acid: An Overlooked Driver of Environmental Change." *Environmental Science & Technology* 45 (5), 1887–1894.

journal *Ecotoxicology* devoted to the effects of MeHg on wildlife.

Response: Although EPA agrees that quantification of acidification effects has remaining uncertainty, the science and methodology has progressed in recent years. Based on recent peer reviewed research including Evans et al.,[298] acid gases can significantly contribute to acidification. The EPA published a comprehensive risk assessment of acidification effects of nitrogen and sulfur deposition[299] and a policy assessment.[300] Given the extent and importance of the sensitive ecosystems evaluated in the review of nitrogen and sulfur deposition any substance that contributes to further acidification must be considered to be affecting the public welfare. The EPA disagrees that the peer reviewed study mentioned by commenter by Evans *et al.*, (2011) is not relevant to U.S. ecosystems. The paper presents evidence that show (1) that HCl is highly mobile in the environment, transferring acidity easily through soils and water, (2) that HCl can transport longer distances than previously thought (given its presence in remote ecosystems, and (3) that it can be a larger driver of acidification than previously thought. The fact that this study took place in the U.K. is itself irrelevant. The chemical interactions of HCl in water are the same the world over and sensitive ecosystems exist in the U.S. as well as in Europe as illustrated in the ecological risk assessment[301] for NO_X and SO_X. Furthermore, the commenter is factually incorrect that EPA is justifying that it is appropriate and necessary to regulate HAP emissions from EGUs based on this one study. The EPA agrees with the commenter that Hg exposure in wildlife is responsible for various adverse health effects in many species across the U.S. and recognizes that research is ongoing in this area. As discussed in the preamble to the proposed rule, the EPA agrees that there are potential environmental risks from exposures of ecosystems through Hg and non-Hg HAP deposition. The EPA cited relevant articles from the special edition of *Ecotoxicology*[302] mentioned by the commenter in the ecosystem effects section on Chapter 5 of the RIA for this rule, which is available in the docket.

G. EPA Affirms the Finding That It Is Appropriate and Necessary to Regulate EGUs To Address Public Health and Environmental Hazards Associated With Emissions of Hg and Non-Hg HAP From EGUs

In response to peer reviews of both the Hg and non-Hg HAP risk analyses, and taking into account public comments, the EPA conducted revised analyses of the risks associated with emissions of Hg and non-Hg HAP from U.S. EGUs. These revised analyses demonstrated that the risk results reported in the preamble to the proposed rule are robust to revisions in response to the peer reviews and public comments.

Specifically, the revised Hg Risk TSD shows that up to 29 percent of modeled watersheds have populations potentially at-risk from exposure to Hg from U.S. EGUs.[303] This 29 percent of watersheds with populations potentially at-risk includes up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD, and up to 24 percent of modeled watersheds where total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. Each of these results independently supports our conclusion that U.S. EGUs pose hazards to public health.

In the preamble to the proposed rule and in the 2000 finding, the EPA explained at length the serious nature of the health effects associated with Hg exposures, and the persistent nature of Hg in the environment. Congress specifically recognized the significant impacts of persistent bioaccumulative pollutants, like Hg, when it enacted section 112(c)(6), which requires the EPA to subject source categories listed pursuant to that section to MACT standards. Congress also required certain studies be conducted under CAA section 112(n) regarding the health effects of Hg. The EPA interprets CAA section 112(n)(1), with regard to Hg, as intended to protect the public, including sensitive populations, against exposures to Hg from EGUs that would exceed the level determined by the EPA to be without appreciable risk, *e.g.*, exposures that are above the RfD for methylmercury (MeHg), or would contribute additional risk in areas where Hg exposures exceed the RfD due to contributions from all sources of Hg. Our recent technical analyses show that 98 percent of the watersheds for which we had fish tissue data have total Hg deposition such that potential exposures exceed the MeHg RfD, above which there is an increased risk of adverse effects on human health. In these watersheds, any reductions in exposures to Hg will reduce risk, and thus the incremental contribution to Hg exposure from any individual source or group of sources, such as EGUs, may reasonably be anticipated to cause additional risk.

As we have explained, in calculating the estimates described above, the EPA has used peer-reviewed methods, and focused on populations likely to be at higher risk of exposure to Hg from U.S. EGUs, *e.g.*, female subsistence fishing populations consuming at the 99th percentile fish consumption rate. The EPA did not, however, use the most conservative assumptions that would lead to upper bound risk estimates. As discussed above and in the revised Hg Risk TSD, we did not use the highest fish tissue cooking loss adjustment factor that was reported in the literature, which, had we done so, would have increased the estimates of Hg exposure substantially. Thus, we believe our analysis could understate risk to the most exposed individual, noting that we have focused on the 99th percentile consumption rate in our estimates.

Further, we were able to assess potential Hg exposures in only a small subset of generally representative watersheds in the U.S. because our analysis was necessarily premised on those water bodies for which we had fish tissue Hg samples. Specifically, we analyzed 3,141 of the approximately 88,000 watersheds in the United States. This limited set of watersheds excludes several of the watersheds with the highest U.S. EGU attributable deposition, and may also not have included watersheds with the highest sensitivity to Hg deposition, *e.g.*, the highest methylation rates (see above). Nevertheless, our analysis of the subset of watersheds we examined demonstrates that almost one third of the watersheds are estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the MeHg RfD. The SAB

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[298] Id.

[299] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Risk and Exposure Assessment for Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur (Final).* EPA–452/R–09–008a. Office of Air Quality Planning and Standards, Research Triangle Park, NC. September. Available on the Internet at *http://www.epa.gov/ttn/naaqs/standards/no2so2sec/data/NOxSOxREASep2009MainContent.pdf.*

[300] U.S. Environmental Protection Agency (U.S. EPA). 2011d. *Policy Assessment for the Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur.* EPA–452/R–11–005a. Office of Air Quality Planning and Standards, Research Triangle Park, NC. February. Available on the Internet at *http://www.epa.gov/ttnnaaqs/standards/no2so2sec/data/20110204pamain.pdf.*

[301] U.S. EPA, 2009.

[302] *Ecotoxicology* 17:83–91, 2008.

[303] This corresponds to 28 percent of modeled watersheds with populations potentially at-risk in the analysis reported in the preamble to the proposed rule.

confirmed that the subset of watersheds we examined is sufficient.

Considering these points and the information on Hg in the record, the EPA believes that 10 percent of watersheds with populations at risk due to U.S. EGU emissions alone is unacceptable, as is 24 percent of watersheds with populations at risk due to U.S. EGU contributions in conjunction with total deposition from other sources. Taking into account the percentage of watersheds at risk, and the potential for even higher percentages to be at risk using more conservative risk assumptions and a more complete coverage of high U.S. EGU Hg deposition watersheds, the EPA concludes that Hg emissions from U.S. EGUs pose a hazard to public health.

Given these findings, and considering that (1) the revised risk analysis showed the percent of modeled watersheds with populations potentially at-risk increased from 28 to 29 percent, and (2) the revised analysis includes 36 percent more watersheds, which significantly expands the coverage in several states, we conclude that the finding that emissions of Hg from U.S. EGUs pose a hazard to public health is confirmed by the national-scale revised Hg Risk TSD. As a result, we conclude that it remains appropriate to regulate Hg emissions from U.S. EGUs because those Hg emissions pose a hazard to public health.

With regards to the revised non-Hg inhalation case studies, the highest estimated individual lifetime cancer risk for the one case study facility (out of 16) with oil-fired EGUs is estimated to be 20 in a million, driven by Ni emissions. For the facilities with coal-fired EGUs, there were five (out of 16) with maximum individual cancer risks greater than one in a million (the highest was five in a million), four of which were driven by emissions of Cr(VI), and one of which was driven by emissions of Ni. Therefore, a total of six facilities exceed the criterion for EGUs to be regulated under CAA section 112. There were also two facilities with coal-fired EGUs with maximum individual cancer risks at one in a million. In the preamble to the proposed rule, we reported that the maximum individual lifetime cancer risk for the one facility with oil-fired EGUs was estimated to be 10 in a million, and that there were 3 coal-fired EGU facilities with maximum individual cancer risks greater than 1 in a million (the highest was 8 in a million), and 1 coal-fired EGU facility with maximum individual cancer risks equal to 1 in a million. Given that (1) the lifetime cancer risk for the oil-fired EGU facility has increased from 10 to 20 in a million, (2) the number of coal-fired EGU facilities with cancer risks greater than 1 in a million has increased from 3 to 5, and (3) the highest risk coal-fired facility still has cancer risks of 5 in a million, which is above the 1 in a million benchmark, we conclude that the finding that emissions of non-Hg HAP from U.S. EGUs pose a hazard to public health is confirmed by the revised non-Hg risk inhalation case studies.

Moreover, some HAP emissions from U.S. EGUs contribute to adverse ecosystem effects. While we did not do new analyses on these topics, we reiterate that (1) Hg emissions from U.S. EGUs pose a hazard to the environment, contributing to adverse impacts on fish-eating birds and mammals, (2) Hg is a persistent bioaccumulative environmental contaminant, and as a result, failing to control Hg emissions from U.S. EGU sources will result in long-term environmental loadings of Hg, above and beyond those loadings caused by immediate deposition of Hg within the U.S.; controlling Hg emissions from U.S. EGUs helps to reduce the potential for environmental hazard from Hg now and in the future, and (4) it is appropriate to regulate those HAP which are not known to cause cancer but are known to contribute to chronic non-cancer toxicity and environmental degradation, such as the acid gases. In addition, we have identified effective controls available to reduce Hg and non-Hg HAP emissions.

In summary, we confirm the findings that Hg and non-Hg HAP emissions from U.S. EGUs each pose hazards to public health and that it remains appropriate to regulate U.S. EGUs under CAA section 112 for those reasons. We also conclude that it remains appropriate to regulate EGUs under CAA section 112 because of the magnitude of Hg and non-Hg emissions and the environmental effects of Hg and some non-Hg emissions, each of which standing alone, supports the appropriate finding. The availability of controls to reduce HAP emissions from EGUs only further supports the appropriate finding.

Our revised analyses still show that in 2016 after implementation of other provisions of the CAA, HAP emissions from U.S. EGUs are reasonably anticipated to pose hazards to public health; therefore, it is necessary to regulate EGUs under CAA section 112. Moreover, HAP emissions from U.S. EGUs are expected to continue to contribute to adverse ecosystem effects. In addition, based on evaluation of the regulations required by the CAA, including the recent CSAPR, it is necessary to regulate U.S. EGUs under CAA section 112 because the only way to ensure permanent reductions in HAP emissions from U.S. EGUs and the associated risks to public health and the environment is through standards set under CAA section 112. While CSAPR is projected to achieve some Hg reductions due to co-control of Hg provided by controls put in place to achieve required reductions in SO_2 emissions, the results of the revised Hg Risk TSD indicate that an unacceptable percentage of modeled watersheds have populations potentially at-risk from U.S. EGU-attributable Hg deposition would remain after implementation of CSAPR. While we modeled slightly higher Hg emissions from U.S. EGUs (*i.e.*, 29 tons of Hg) in our risk analysis compared to the most recent estimate of 27 tons, we do not believe this 2 ton difference would substantially change our finding that Hg emissions from U.S. EGUs pose a hazard to public health or the Hg risks reported in the preamble to the proposed rule, as this represents less than a 10 percent reduction in Hg emissions. In addition, the actual reductions in Hg that will occur due to application of controls to meet the SO_2 emissions requirements of CSAPR may differ from those projected to occur, due to differences in the technologies that individual EGU sources choose to install. The only way to ensure reductions in Hg, including those modeled as resulting from the CSAPR, is to directly regulate Hg emissions under CAA section 112.

In summary, we confirm the findings that it is necessary to regulate HAP emissions from U.S. EGUs because (1) the national-scale Hg Risk TSD shows that the hazards to public health posed by Hg emissions from U.S. EGUs will not be addressed through imposition of the CAA, (2) we cannot be certain that the identified cancer risks attributable to U.S. EGUs will be addressed through imposition of the requirements of the CAA, (3) the environmental hazards posed by acidification will not be fully addressed through imposition of the CAA, (4) regulation under CAA section 112 is the only way to ensure that all HAP emissions reductions that have been achieved since 2005 remain permanent, and (5) direct control of Hg emissions affecting U.S. deposition is only possible through regulation of U.S. emissions as we are unable to control global emissions directly. All of these findings independently support a finding that it is necessary to regulate U.S. EGUs under CAA section 112.

Based on these findings, the Agency affirms its finding that it remains appropriate and necessary to regulate

coal- and oil-fired EGUs under CAA section 112, and maintains that the inclusion of coal- and oil-fired EGUs on the CAA section 112(c) list of source categories regulated under CAA section 112 remains valid.

IV. Denial of Delisting Petition

During the comment period on the proposed rule, UARG submitted a petition pursuant to CAA section 112(c)(9), asking the Agency to delete a portion of the EGU source category from the list of source categories to be regulated under CAA section 112. Specifically, UARG asks that EPA delist coal-fired EGUs from the CAA section 112(c) source category list. A copy of UARG's petition has been placed in the docket for today's rulemaking, along with the analysis conducted by EPRI that UARG uses to support its petition (hereinafter referred to as UARG's analysis). In support of its petition, UARG asserts that: (1) No coal-fired EGU or group of coal-fired EGUs will emit HAP in amounts that will cause a lifetime cancer risk greater than one in one million; and (2) no coal-fired EGU or group of coal-fired EGUs will emit non-carcinogenic HAP in amounts that will exceed a level which is adequate to protect public health with an ample margin of safety or cause adverse environmental effects. We disagree with UARG's assertions and for the reasons set forth below are denying UARG's petition to delist coal-fired EGUs from the section 112(c) source category list.

A. Requirements of CAA Section 112(c)(9)

CAA section 112(c)(9)(B) provides that "[t]he Administrator may delete any source category" from the section 112(c) source category list if the Agency determines that: (i) For HAP that may cause cancer in humans, "no source in the category (or group of sources in the case of area sources) emits such hazardous air pollutants in quantities which may cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed to emissions of such pollutants from the source (or group of sources in the case of area sources)"; and (ii) for HAP that may result in human health effects other than cancer or adverse environmental effects, "a determination that emissions from no source in the category or subcategory concerned (or group of sources in the case of area sources) exceed a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source."

The EPA has the discretion to delete a source category under CAA section 112(c)(9)(B), but only if EPA concludes that the relevant requirements of CAA section 112(c)(9)(B) have been met. HAP emissions from EGUs present both cancer risks, which implicate the requirements of CAA section 112(c)(9)(B)(i), and non-cancer human health effects or adverse environmental effects, which implicate the requirements of CAA section 112(c)(9)(B)(ii). As such, UARG bears the burden of demonstrating that the requirements of *both* clauses are met.

B. Rationale for Denying UARG's Delisting Petition

The EPA is denying UARG's petition to delist EGUs from the CAA section 112(c) source category list. UARG improperly seeks to delist a portion of a CAA section 112(c) listed source category that emits carcinogens, which is contrary to the plain language of CAA section 112(c)(9). Even setting aside this fundamental defect, UARG has failed to meet the requirements of CAA section 112(c)(9)(B).

1. UARG's Attempt to Delist a Portion of a Listed Source Category Conflicts With D.C. Circuit Precedent

In December 2000, the EPA listed coal- and oil-fired EGUs as a single source category. UARG asks the Agency to delist a portion of that listed source category: Coal-fired EGUs. UARG's request conflicts, however, with D.C. Circuit precedent, which provides that for categories, like EGUs, that pose cancer risks, the EPA may not delist a portion of a source category. *NRDC* v. *U.S. EPA*, 489 F.3d 1364 (D.C. Cir. 2007). Specifically, in *NRDC*, the D.C. Circuit held that the Agency's attempt to delist a "low-risk" subcategory was "contrary to the plain language of the statute," and that the statute only authorized the agency to remove source categories pursuant to section 112(c)(9). *Id. at 1373* ("Because EPA's interpretation of Section 112(c)(9) as allowing it to exempt the risk-based subcategory is contrary to the plain language of the statute, the EPA's interpretation fails at Chevron step one.").

UARG's request is indistinguishable from the situation before the court in *NRDC*. UARG does not seek to delist coal- and oil-fired EGUs, which is the source category that EPA listed, but rather a portion of that category. UARG also does not dispute that coal-fired EGUs emit carcinogenic HAP. Because UARG's request to delist is contrary to the plain language of CAA section 112(c)(9)(B) and *NRDC*, we are denying the delisting petition.

2. Even Assuming, for the Sake of Argument, That EPA Could Delist a Portion of a Source Category, UARG has Failed to Meet the Requirements of CAA Section 112(c)(9)

Even assuming, for the sake of argument, that EPA could delist a portion of a source category that emits carcinogens, which it cannot, UARG has failed to demonstrate that the requirements for delisting in CAA section 112(c)(9)(i) and (ii) have been met. UARG contends that it used EPA's models and approaches, as well as the most recent data. We have carefully reviewed UARG's analyses, however, and found certain flaws that we believe bias their risk results low. Specifically, we identified flaws in emissions estimation. UARG developed estimates for all EGU facilities using data which pre-date the 2010 ICR emissions measurement data that EPA obtained to support this rule. UARG also relied upon an emissions equation developed by EPRI and DOE to develop its metal emissions estimates. With regard to that approach, the EPA analysis of the ICR data has found that the regression approach is not a good predictor of actual EGU emissions. Furthermore, we found fault with their use of the geometric mean and their outlier analysis for computing emission factors. The EPA analysis has found that the geometric mean approach underpredicts actual emissions by an average of more than seventy percent. This had an especially large impact on the arsenic, chromium, and nickel emissions estimates. These and other issues are explained in further detail in the response to comments document. As a result, we believe the resulting risk estimates in UARG's analysis are biased low. In addition, we note that there are dispersion model refinements that are not included in the UARG analyses, but were included in EPA's analysis. For example, for the dispersion modeling of the 16 non-Hg case studies, the EPA considered building downwash and used time-varying emissions, neither of which were used in UARG's analysis. These factors could also bias the UARG risk estimates low.

However, even taking UARG's analysis at face value and accepting, for arguments' sake, their assumptions and emissions estimates, UARG's own data supports denial of the petition because UARG itself identifies a maximum individual cancer risk exceeding 1 in a million, which is the statutory threshold in CAA section 112(c)(9)(B)(i). Specifically, UARG's multi-pathway

model plant ingestion risk analysis concluded that adult anglers would face cancer risks of 4 in a million. For this reason alone, the petition should be denied.

UARG dismisses the 4 in a million cancer result, arguing that the refined model plant multipathway risk assessment that it conducted is "overly conservative." UARG conducted its multi-pathway risk analysis to evaluate the risks associated with ingesting persistent and bioaccumulative HAP which are emitted into the atmosphere and subsequently deposit into the environment and bioaccumulate in animals which are eventually consumed as food. Instead of conducting this multipathway analysis for each EGU facility, UARG instead analyzed multi-pathway risks by evaluating a single model plant. Nothing in the record indicates, however, that UARG's model plant represents the worst-case scenario for cancer human health risks from any EGU. Indeed, although UARG claims in its petition that the site selected for its case study is "likely as close to a worst-case scenario as is possible given the numerous variables associated with ingestion pathway risks" (UARG petition at 12), the supporting documentation for that case study specifically acknowledges that its fictional model plant scenario "is not intended to represent the risk due to emissions from an actual plant or the highest level of risk that could be associated with a coal-fired power plant at any location" (EPRI at 1). The statute requires that no source in the category may cause a lifetime cancer risk greater than one in one million to the most exposed individual, and UARG has failed to make this showing. UARG has neither modeled multi-pathway risks for a worst-case model facility, nor evaluated the multipathway risks associated with each individual EGU facility. Accordingly, UARG has not made the demonstration required by CAA section 112(c)(9)(B)(i). But, even focusing on the multi-pathway risk analysis that UARG did conduct, which admittedly does not represent a worst-case facility, UARG's analysis still shows cancer risks greater than one in a million. Accordingly, UARG's petition must be denied.

Although it is not necessary to reach the requirements of CAA section 112(c)(9)(B)(ii) that address non-cancer human health risks, we note that UARG has also failed to show that "emissions from no source in the category * * * exceed a level which is adequate to protect public health with an ample margin of safety." Again, even accepting, for argument's sake, the conclusions in UARG's analysis, UARG only evaluated the non-cancer *inhalation* risks associated with each EGU facility. It did not conduct a similar analysis to assess multipathway risks for each EGU facility. Instead, it conducted a model plant analysis and admits that such model plant does not represent the worst-case scenario for noncancer human health risks from any EGU. Thus, the analysis fails to fully characterize noncancer multipathway risks for the source category, and UARG's petition must be denied on this basis as well.

Finally, UARG failed to meet its burden of showing that "no adverse environmental effect will result from emissions from any source" pursuant to CAA section 112(c)(9)(B)(ii). UARG analyzed environmental effects only in conjunction with its model plant. Because UARG's model plant does not represent the worst-case scenario for environmental effects, UARG's analysis falls short and fails to characterize fully the potential environmental impacts, and UARG's petition must be denied.

For all of these reasons, the EPA denies UARG's petition to delist coal-fired EGUs from the CAA section 112(c) source category list.

C. EPA's Technical Analyses for the Appropriate and Necessary Finding Provide Further Support for the Conclusion That Coal-Fired EGUs Should Remain a Listed Source Category

The EPA reasonably concluded in December 2000, based on the information available to the Agency at that time, that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under CAA section 112(d). As discussed in section III above, the EPA conducted additional, extensive technical analyses based on recent data that confirm it remains appropriate and necessary to regulate HAP from coal- and oil-fired EGUs, because such EGUs continue to pose hazards to public health. HAP emissions from coal- and oil-fired EGUs also continue to cause adverse environmental effects. UARG advances several arguments, challenging the analyses the Agency completed in support of the proposed rule. We address those arguments in section III above. The Agency's analyses supporting the appropriate and necessary finding confirm that EGUs cannot be delisted pursuant to CAA section 112(c)(9).

Specifically, as explained further in section III above, the EPA analyzed non-Hg inhalation risks from 16 EGU facility case studies, including both coal- and oil-fired EGUs, as part of its technical analyses supporting the appropriate and necessary finding. That analysis demonstrates that there are 6 EGU facilities (of the 16 that we analyzed) with cancer risks exceeding one in one million. These cancer risk levels exceed the delisting criteria set forth in CAA section 112(c)(9)(B)(i), and confirm that EGUs must remain a listed source category. As explained above, some commenters assert that EPA's analysis of non-Hg inhalation risks from EGUs conducted in support of the proposal for this rulemaking overstated emissions from, and risks associated with, EGUs. These commenters argue that the analysis supporting UARG's petition more appropriately assesses EGU risk. The EPA disagrees with these comments and addresses these comments in section III above.

Significantly, the EPA based its analysis of 16 case study EGUs directly on the 2010 emissions test data from EGUs obtained through the ICR. The EPA's 16 case study analysis used emissions data either taken directly from the 2010 emissions test data, or derived using emissions factors based on the 2010 data for similar EGU units. The EPA also included dispersion model refinements in its final case studies, as noted above. Further, the EPA re-analyzed the 16 case studies that we conducted for the proposal and revised those analyses consistent with new non-Hg HAP emissions data and corrected stack parameters provided by commenters (including UARG) during the comment period on the proposed rule. The EPA received revised information concerning emissions tests, stack heights and stack diameters for some of the case study EGU facilities. The EPA incorporated all of these corrections into our analysis and then re-analyzed the risks for the 16 case study facilities. When completed, the EPA determined that the corrections incorporated into the reanalysis had little effect on the overall results. In the final rule, the EPA concludes that the maximum individual inhalation cancer risks for 6 out of the 16 case study EGU facilities are greater than 1 in a million. These cancer risk levels confirm that EGUs do not satisfy the delisting criterion of CAA section 112(c)(9)(B)(i) and thus should remain a listed source category.

The EPA's national-scale Hg Risk TSD supporting the appropriate and necessary finding also confirm that Hg emissions from coal- and oil-fired US EGUs are reasonably anticipated to pose a hazard to public health. As discussed

in section III above, the EPA interprets CAA section 112(n)(1), with regard to mercury, as intended to protect the public, including sensitive populations, against exposures to Hg from EGUs that would exceed the level determined by EPA to be without appreciable risk, e.g., exposures that are above the RfD for methylmercury (MeHg), or would contribute additional risk in areas where Hg exposures exceed the RfD due to contributions from all sources of Hg.

In order to determine whether EGU Hg emissions pose a hazard to public health, the EPA conducted a national-scale Hg Risk TSD focused on populations with high levels of self-caught freshwater fish consumption. The results of the Hg Risk TSD show that 98 percent of modeled watersheds have total exposures to MeHg that exceed the MeHg RfD, above which there is an increased risk of adverse effects on human health. In these watersheds, any reductions in exposures to Hg will reduce risk, and thus the incremental contribution to Hg exposure from any individual source or group of sources, such as EGUs, may reasonably be anticipated to cause additional risk. The Hg Risk TSD focused on those watersheds that either exceeded the RfD based on U.S. EGU attributable deposition alone, without considering other sources of deposition, or watersheds that exceed the RfD due to total Hg deposition and to which U.S. EGUs contributed at least 5 percent of the Hg deposition. The results of that analysis show that up to 29 percent of the modeled watersheds have populations that are potentially at-risk from exposure to Hg from U.S. EGUs, including up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD, and up to 24 percent of modeled watersheds where total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. This approach to assessing national risks from Hg deposition from EGUs was supported by the independent peer review conducted by the Science Advisory Board, as discussed fully in section III.

Finally, as discussed in section III, based on this assessment, the EPA has confirmed that Hg emitted from U.S. EGUs pose a hazard to public health and it is appropriate to regulate U.S. EGUs under CAA section 112. This determination and the confirmatory assessments support our conclusion that UARG's delisting petition must be denied.

UARG attempts to dismiss the results of EPA's national-scale Hg Risk TSD, arguing that EPA cannot consider the risks posed by EGUs in conjunction with any other risks, including those from other source categories. Nothing in CAA section 112(c)(9), however, provides that the Agency cannot consider background or emissions due to other sources. CAA section 112(c)(9)(B)(ii) provides that "no source in the category or subcategory concerned (or group of sources in the case of area sources) exceed a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source." This language could be read to provide that the Agency consider only the risks associated with the source category at issue, and ignore how those risks fit with real-world exposures.[304] However, the language could also be read to provide that the Agency consider the cumulative effect of HAP emissions from the individual sources in the category in conjunction with the HAP emissions from other sources. The latter is a reasonable interpretation, especially when considering how the public is exposed to HAP emissions. Considering the individual sources in a source category in isolation treats the sources as if they exist in a vacuum, which does not mirror reality. Such an approach is particularly problematic for environmentally persistent HAP that bio-accumulate in the food chain, such as mercury.[305]

Here, the record demonstrates that 98 percent of the watersheds EPA modeled have total exposures to MeHg that exceed the MeHg RfD, above which there is increased risk of adverse effects on human health, especially on the developing nervous systems of children during gestation. EGUs remain one of the largest unregulated sources of Hg emissions, and those emissions continue to contribute to Hg exposures and risk. UARG seeks to ignore the fact that exposures above the RfD exist in almost every watershed we modeled, and instead focuses on the contribution provided solely by EGUs. The EPA did as UARG asked and found that up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD. Thus, even focusing on EGU emissions in a vacuum, which we do not believe is appropriate or required under CAA section 112(c)(9), we still found that up to 10 percent of the watersheds exceed the RfD due to EGU emissions even before taking into account the numerous other sources of Hg deposition, and we believe this to be an unacceptable percentage of watersheds above the RfD. Due to the persistent, bioacccumulative nature of Hg, among other factors, we believe it is appropriate to consider the combined impact of Hg emissions from EGUs and other sources of Hg. Thus, we also considered the 24 percent of modeled watersheds where, even though U.S. EGU emissions alone are not enough to cause exposures that exceed the RfD, those emissions contribute at least 5 percent of total exposures to MeHg that exceed the RfD. The combined total of 29 percent of modeled watersheds where U.S. EGUs cause or contribute to MeHg exposures above the RfD is clearly unacceptable and thus the UARG petition to delist must be denied.

Thus, the technical analyses the Agency conducted in support of the appropriate and necessary finding confirm that EGUs should remain a listed source category.

V. Summary of This Final NESHAP

This section summarizes the requirements of the final EGU NESHAP. Section VI below summarizes the significant changes to this final rule following proposal.

A. What is the source category regulated by this final rule?

This final rule affects coal- and oil-fired EGUs.

B. What is the affected source?

An existing affected source under this final rule is the collection of coal- or oil-fired EGUs in a subcategory within a single contiguous area and under common control. A new affected source is each coal- or oil-fired EGU for which construction or reconstruction began after May 3, 2011.

[304] The same is true with respect to section 112(c)(9)(B)(i).

[305] In a prior rulemaking, EPA stated that the language in section 112(c)(9)(B)(ii) "does not direct EPA to extend its analysis to either emissions from other sources in other categories or subcategories or to non-attributable background concentrations." 71 FR 8347 (Feb. 16, 2006). The preamble to that rule repeatedly states that the "focus" of the delisting determination in that rule was on emissions from sources in the category under review. *See* 71 FR 8346–47. The preamble went on to compare section 112(c)(9)(B) to section 112(f)(2)(A) in a way that suggested that EPA can consider risks presented by sources other than the subject source category under section 112(f)(2), but not under section 112(c)(9). We do not believe the language of section 112(c)(9) compels any different treatment. The section 112(f) analysis occurs after a source category has already complied with section 112(d) standards, whereas, potential delistings under section 112(c)(9) may involve source categories unregulated by section 112. A delisting decision is significant in that the category that is delisted will no longer be subject to HAP regulation under the Act. It is difficult to justify why we would examine risks from other sources under section 112(f), but not under section 112(c)(9), where Congress established such a specific test for delisting.

CAA section 112(a)(8) defines an EGU as: a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit.

If an EGU burns coal (either as a primary fuel or as a supplementary fuel) or any combination of coal with another fuel (except for solid waste as noted below) where the coal accounts for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date, the unit is considered to be coal-fired under this final rule.

If a unit is not a coal-fired unit and burns only oil or burns oil in combination with a fuel other than coal (except solid waste as noted below) where the oil accounts for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date, the unit is considered to be oil-fired under this final rule.

As noted below, the EPA is finalizing in this rule a definition to determine whether the combustion unit is "fossil fuel fired" such that it is considered an EGU as defined in CAA section 112(a)(8) and, thus, potentially subject to this final rule. In addition, using the construct of the definition of "oil-fired" from the ARP, we are finalizing in this rule a requirement that the unit fire coal or oil (or natural gas), or any combination thereof, for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year to be considered a "fossil fuel-fired" EGU as defined in CAA section 112(a)(8). However, if a new or existing EGU is not coal- or oil-fired, and the unit burns natural gas exclusively or burns natural gas in combination with another fuel where the natural gas constitutes 10 percent or more of the average annual heat input during any 3 calendar years or 15 percent or more of the annual heat input during any 1 calendar year, the unit is considered to be natural gas-fired EGU and not subject to this final rule. As discussed later, we believe that this definition will address those situations where an EGU co-fires limited amounts of either coal or oil with natural gas or other non-fossil fuels (e.g., biomass).

If an EGU combusts solid waste, standards issued pursuant to CAA section 129 apply to that EGU, rather than this final rule.

C. What are the pollutants regulated by this final rule?

For coal-fired EGUs, this final rule regulates HCl as a surrogate for acid gas HAP, with an alternate of SO_2 as a surrogate for acid gas HAP for coal-fired EGUs with FGD systems installed and operational; filterable PM as a surrogate for non-mercury HAP metals, with total non-mercury HAP metals and individual non-mercury HAP metals as alternative equivalent standards; Hg; and organic HAP. For oil-fired EGUs, this final rule regulates HCl and HF; filterable PM as a surrogate for total HAP metals, with individual HAP metals as alternative equivalent standards; and organic HAP.

D. What emission limits and work practice standards must I meet and what are the subcategories in the final rule?

We are finalizing the emission limitations presented in Tables 3 and 4 of this preamble. Within the two major subcategories of "coal" and "oil," emission limitations were developed for new and existing sources for seven subcategories, two for coal-fired EGUs, one for IGCC EGUs burning synthetic gas derived from coal- and/or solid oil-derived fuel, one for solid oil-derived fuel-fired EGUs, and four for liquid oil-fired EGUs, as described in more detail below. The limited-use liquid oil-fired subcategory, discussed elsewhere in this preamble, is not presented in Table 3 because only work practice standards apply to this subcategory.

TABLE 3—EMISSION LIMITATIONS FOR COAL-FIRED AND SOLID OIL-DERIVED FUEL-FIRED EGUS

Subcategory	Filterable particulate matter	Hydrogen chloride	Mercury
Existing—Unit not low rank virgin coal	3.0E–2 lb/MMBtu. (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu. (2.0E–2 lb/MWh)	1.2E0 lb/TBtu. (1.3E–2 lb/GWh).
Existing—Unit designed low rank virgin coal	3.0E–2 lb/MMBtu. (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu. (2.0E–2 lb/MWh)	1.1E+1 lb/TBtu. (1.2E–1 lb/GWh). 4.0E0 lb/TBtu [a]. (4.0E–2 lb/GWh [a]).
Existing—IGCC	4.0E–2 lb/MMBtu. (4.0E–1 lb/MWh)	5.0E–4 lb/MMBtu. (5.0E–3 lb/MWh)	2.5E0 lb/TBtu. (3.0E–2 lb/GWh).
Existing—Solid oil-derived	8.0E–3 lb/MMBtu. (9.0E–2 lb/MWh)	5.0E–3 lb/MMBtu. (8.0E–2 lb/MWh)	2.0E–1 lb/TBtu. (2.0E–3 lb/GWh).
New—Unit not low rank virgin coal	7.0E–3 lb/MWh	4.0E–4 lb/MWh	2.0E–4 lb/GWh.
New—Unit designed for low rank virgin coal	7.0E–3 lb/MWh	4.0E–4 lb/MWh	4.0E–2 lb/GWh.
New—IGCC	7.0E–2 lb/MWh [b] 9.0E–2 lb/MWh [c]	2.0E–3 lb/MWh [d]	3.0E–3 lb/GWh [e].
New—Solid oil-derived	2.0E–2 lb/MWh	4.0E–4 lb/MWh	2.0E–3 lb/GWh.

Note: lb/MMBtu = pounds pollutant per million British thermal units fuel input.
lb/TBtu = pounds pollutant per trillion British thermal units fuel input.
lb/MWh = pounds pollutant per megawatt-hour electric output (gross).
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross).
[a] Beyond-the-floor limit as discussed elsewhere.
[b] Duct burners on syngas; based on permit levels in comments received.

[c] Duct burners on natural gas; based on permit levels in comments received.
[d] Based on best-performing similar source.
[e] Based on permit levels in comments received.

TABLE 4—EMISSION LIMITATIONS FOR LIQUID OIL-FIRED EGUS

Subcategory	Filterable particulate matter	Hydrogen chloride	Hydrogen fluoride
Existing—Liquid oil—continental	3.0E–2 lb/MMBtu (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu (1.0E–2 lb/MWh)	4.0E–4 lb/MMBtu. (4.0E–3 lb/MWh).
Existing—Liquid oil—non-continental	3.0E–2 lb/MMBtu (3.0E–1 lb/MWh)	2.0E–4 lb/MMBtu (2.0E–3 lb/MWh)	6.0E–5 lb/MMBtu. (5.0E–4 lb/MWh).
New—Liquid oil—continental	7.0E–2 lb/MWh	4.0E–4 lb/MWh	4.0E–4 lb/MWh.
New—Liquid oil—non-continental	2.0E–1 lb/MWh	2.0E–3 lb/MWh	5.0E–4 lb/MWh.

We are also finalizing alternate equivalent emission standards (for certain subcategories) to the final surrogate standards in three areas: SO_2 (for HCl), individual non-mercury metals and total non-mercury metals (for filterable PM) from coal- and solid oil-derived fuel-fired EGUs, and individual and total metals (for filterable PM) from oil-fired EGUs. The final alternate emission limitations are provided in Tables 5 and 6 of this preamble.

TABLE 5—ALTERNATE EMISSION LIMITATIONS FOR EXISTING COAL- AND OIL-FIRED EGUS

Subcategory/Pollutant	Coal-fired EGUs	IGCC	Liquid oil, continental	Liquid oil, non-continental	Solid oil-derived
SO_2	2.0E–1 lb/MMBtu (1.5E0 lb/MWh)	NA	NA	NA	3.0E–1 lb/MMBtu. (2.0E0 lb/MWh).
Total non-mercury metals	5.0E–5 lb/MMBtu (5.0E–1 lb/GWh)	6.0E–5 lb/MMBtu (5.0E–1 lb/GWh)	8.0E–4 lb/MMBtu (8.0E–3 lb/MWh)[a]	6.0E–4 lb/MMBtu (7.0E–3 lb.MWh)[a]	4.0E–5 lb/MMBtu. (6.0E–1 lb/GWh).
Antimony, Sb	8.0E–1 lb/TBtu (8.0E–3 lb/GWh)	1.4E0 lb/TBtu (2.0E–2 lb/GWh)	1.3E+1 lb/TBtu (2.0E–1 lb/GWh)	2.2E0 lb/TBtu (2.0E–2 lb/GWh)	8.0E–1 lb/TBtu. (8.0E–3 lb/GWh).
Arsenic, As	1.1E0 lb/TBtu (2.0E–2 lb/GWh)	1.5E0 lb/TBtu (2.0E–2 lb/GWh)	2.8E0 lb/TBtu (3.0E–2 lb/GWh)	4.3E0 lb/TBtu (8.0E–2 lb/GWh)	3.0E–1 lb/TBtu. (5.0E–3 lb/GWh).
Beryllium, Be	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	1.0E–1 lb/TBtu (1.0E–3 lb/GWh)	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	6.0E–1 lb/TBtu (3.0E–3 lb/GWh)	6.0E–2 lb/TBtu. (6.0E–4 lb/GWh).
Cadmium, Cd	3.0E–1 lb/TBtu (3.0E–3 lb/GWh)	1.5E–1 lb/TBtu (2.0E–3 lb/GWh)	3.0E–1 lb/TBtu (2.0E–3 lb/GWh)	3.0E–1 lb/TBtu (3.0E–3 lb/GWh)	3.0E–1 lb/TBtu. (4.0E–3 lb/GWh).
Chromium, Cr	2.8E0 lb/TBtu (3.0E–2 lb/GWh)	2.9E0 lb/TBtu (3.0E–2 lb/GWh)	5.5E0 lb/TBtu (6.0E–2 lb/GWh)	3.1E+1 lb/TBtu (3.0E–1 lb/GWh)	8.0E–1 lb/TBtu. (2.0E–2 lb/GWh).
Cobalt, Co	8.0E–1 lb/TBtu (8.0E–3 lb/GWh)	1.2E0 lb/TBtu (2.0E–2 lb/GWh)	2.1E+1 lb/TBtu (3.0E–1 lb/GWh)	1.1E+2 lb/TBtu (1.4E0 lb/GWh)	1.1E0 lb/TBtu. (2.0E–2 lb/GWh).
Lead, Pb	1.2E0 lb/TBtu (2.0E–2 lb/GWh)	1.9E+2 lb/MMBtu (1.8E0 lb/MWh)	8.1E0 lb/TBtu (8.0E–2 lb/GWh)	4.9E0 lb/TBtu (8.0E–2 lb/GWh)	8.0E–1 lb/TBtu. (2.0E–2 lb/GWh).
Manganese, Mn	4.0E0 lb/TBtu (5.0E–2 lb/GWh	2.5E0 lb/TBtu (3.0E–2 lb/GWh)	2.2E+1 lb/TBtu (3.0E–1 lb/GWh)	2.0E+1 lb/TBtu (3.0E–1 lb/GWh)	2.3E0 lb/TBtu. (4.0E–2 lb/GWh).
Mercury, Hg	NA	NA	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	4.0E–2 lb/TBtu (4.0E–4 lb/GWh).	NA.
Nickel, Ni	3.5E0 lb/TBtu (4.0E–2 lb/GWh)	6.5E0 lb/TBtu (7.0E–2 lb/GWh)	1.1E+2 lb/TBtu (1.1E0 lb/GWh)	4.7E+2 lb/TBtu (4.1E0 lb/GWh)	9.0E0 lb/TBtu. (2.0E–1 lb/GWh).
Selenium, Se	5.0E0 lb/TBtu (6.0E–2 lb/GWh)	2.2E+1 lb/TBtu (3.0E–1 lb/GWh)	3.3E0 lb/TBtu (4.0E–2 lb/GWh)	9.8E0 lb/TBtu (2.0E–1 lb/GWh)	1.2E0 lb/TBtu. (2.0E–2 lb/GWh).

NA = Not applicable.
[a] Includes Hg.

TABLE 6—ALTERNATE EMISSION LIMITATIONS FOR NEW COAL- AND OIL-FIRED EGUS

Subcategory/Pollutant	Coal-fired EGUs	IGCC[a]	Liquid oil, continental, lb/GWh	Liquid oil, non-continental, lb/GWh	Solid oil-derived
SO_2	4.0E–1 lb/MWh	4.0E–1 lb/MWh	NA	NA	4.0E–1 lb/MWh
Total non-mercury metals	6.0E–2 lb/GWh	4.0E–1 lb/GWh	2.0E–4 lb/MWh[b]	7.0E–3 lb/MWh[b]	6.0E–1 lb/GWh
Antimony, Sb	8.0E–3 lb/GWh	2.0E–2 lb/GWh	1.0E–2	8.0E–3	8.0E–3 lb/GWh
Arsenic, As	3.0E–3 lb/GWh	2.0E–2 lb/GWh	3.0E–3	6.0E–2	3.0E–3 lb/GWh
Beryllium, Be	6.0E–4 lb/GWh	1.0E–3 lb/GWh	5.0E–4	2.0E–3	6.0E–4 lb/GWh
Cadmium, Cd	4.0E–4 lb/GWh	2.0E–3 lb/GWh	2.0E–4	2.0E–3	7.0E–4 lb/GWh
Chromium, Cr	7.0E–3 lb/GWh	4.0E–2 lb/GWh	2.0E–2	2.0E–2	6.0E–3 lb/GWh
Cobalt, Co	2.0E–3 lb/GWh	4.0E–3 lb/GWh	3.0E–2	3.0E–1	2.0E–3 lb/GWh
Lead, Pb	2.0E–3 lb/GWh	9.0E–3 lb/GWh	8.0E–3	3.0E–2	2.0E–2 lb/GWh
Mercury, Hg	NA	NA	1.0E–4	4.0E–4	2.0E–3 lb/GWh
Manganese, Mn	4.0E–3 lb/GWh	2.0E–2 lb/GWh	2.0E–2	1.0E–1	7.0E–3 lb/GWh

TABLE 6—ALTERNATE EMISSION LIMITATIONS FOR NEW COAL- AND OIL-FIRED EGUS—Continued

Subcategory/Pollutant	Coal-fired EGUs	IGCC [a]	Liquid oil, continental, lb/GWh	Liquid oil, non-continental, lb/GWh	Solid oil-derived
Nickel, Ni	4.0E–2 lb/GWh	7.0E–2 lb/GWh	9.0E–2	4.1E0	4.0E–2 lb/GWh
Selenium, Se	6.0E–3 lb/GWh	3.0E–1 lb/GWh	2.0E–2	2.0E–2	6.0E–3 lb/GWh

NA = Not applicable.
[a] Based on best-performing similar source.
[b] Includes Hg.

As noted elsewhere in this preamble, we are finalizing a requirement to use filterable PM as a surrogate for the non-mercury metallic HAP and HCl as a surrogate for the acid gas HAP for all subcategories of coal-fired EGUs and for the solid oil derived fuel-fired EGUs. For all liquid oil-fired EGUs, we are finalizing a requirement to use filterable PM as a surrogate for the total metallic HAP, and we are finalizing HCl and HF limits.

In addition, we are finalizing alternative standards for certain HAP for some subcategories. The alternative pollutants and subcategories are as follows: (1) SO_2 as a surrogate to HCl for all subcategories with add-on FGD systems (except liquid oil-fired subcategories as there were no existing units from which to base an alternate SO_2 limit); (2) individual non-mercury metallic HAP as an alternate to filterable PM for all subcategories (except that it includes Hg for liquid oil-fired subcategories); and (3) total non-mercury metallic HAP as an alternate to filterable PM for all subcategories (except that it includes Hg for liquid oil-fired subcategories). These alternative standards are discussed elsewhere in this preamble.

We are finalizing a beyond-the-floor standard for Hg only for all existing coal-fired units designed for low rank virgin coal based on the use of activated carbon injection (ACI) for Hg control, as described elsewhere in this preamble. The EPA has determined that this beyond-the-floor level is achievable after considering the relevant CAA section 112(d)(2) provisions.

As noted elsewhere in this preamble, we are also finalizing a compliance assurance option that would allow you to monitor liquid oil fuel moisture to demonstrate that fuel moisture content is no greater than 1.0 percent. Provided that demonstration is made, you will not have to conduct additional testing and monitoring to demonstrate compliance with the HCl and HF emission limits for units in both liquid oil subcategories (*i.e.*, continental and non-continental).

Pursuant to CAA section 112(h), we are finalizing a work practice standard for organic HAP, including emissions of dioxins and furans, for all subcategories of EGUs. The work practice standard being finalized requires the implementation of periodic burner tune-up procedures described elsewhere in this preamble. We are finalizing work practice standards because the significant majority of data for measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods, even when long duration (around 8 hour) test runs are considered. As such, we consider it impracticable to measure emissions from these units. As discussed at proposal, we believe the inaccuracy of a majority of measurements, coupled with the extended sampling times used, allow a work practice standard under CAA section 112(h) to apply to these HAP.[306] We believe that a work practice standard will lead to a better environmental outcome than would be obtained through a requirement to measure a pollutant for which results may or may not be obtained. We believe that the work practice standard will result in actions being taken that will reduce emissions of these HAP.

In addition, as discussed below, we are creating a subcategory for limited use liquid oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input and we are establishing work practice standards applicable to such units pursuant to CAA section 112(h).

We are finalizing that new or existing EGUs are "coal-fired" if they combust coal more than 10 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year and meet the final definition of "fossil fuel-fired." We are finalizing that an EGU is considered to be in the coal-fired "unit designed for coal greater than or equal to 8,300 Btu/lb" subcategory if the EGU: (1) meets the final definitions of "fossil fuel-fired" and "coal-fired electric utility steam generating unit;" and (2) is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

We are finalizing that the EGU is considered to be in the "unit designed for low rank virgin coal" subcategory if the EGU: (1) meets the final definitions of "fossil fuel-fired" and "coal-fired electric utility steam generating unit;" and (2) is designed to burn and is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) and that is constructed and operates at or near the mine that produces such coal.[307]

We are finalizing that the EGU is considered to be an IGCC unit if the EGU: (1) Combusts a synthetic gas derived from gasified coal or solid oil-derived fuel (*e.g.*, petroleum coke, pet coke), (2) meets the final definition of "fossil fuel-fired," and (3) is classified as an IGCC unit. We are not subcategorizing IGCC EGUs based on the source of the syngas used (e.g., coal, petroleum coke). Based on information available to the Agency, although the fuel characteristics of coal and petcoke are quite different, the syngas products from both feedstocks have similar HAP content and similar HAP emissions characteristics that can be controlled in a similar manner.[308]

We are finalizing that the EGU is considered to be in the "Continental liquid oil-fired" subcategory if (1) meets the final definitions of "oil-fired electric utility steam generating unit" and "fossil fuel-fired;" and (2) is located in the continental United States (U.S.).

We are finalizing that the EGU is considered to be "Non-continental liquid oil-fired" subcategory if (1) meets the final definitions of "oil-fired electric utility steam generating unit" and

[306] We would also note that the EPA, as a part of the Industrial Boiler MACT reconsideration proposal that was signed on December 2, 2011, is proposing to establish work practice standards for control of dioxins and furans from industrial boilers.

[307] ASTM Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

[308] U.S. Department of Energy, Wabash River Coal Gaification Repowering Project. Project Performance Summary; Clean Coal Technology Demonstration Program. DOE/FE–0448. July 2002. EPA–HQ–OAR–2009–0234–2933.

"fossil fuel-fired;" and (2) is located outside continental U.S.

We are finalizing that the EGU is considered to be "solid oil-derived fuel-fired" if (1) the EGU is not a coal-fired EGU and burns solid oil-derived fuel (*e.g.*, petroleum coke, pet coke); and (2) meets the final definitions of "oil-fired electric utility steam generating unit" and "fossil fuel-fired."

We are finalizing that the EGU is considered to be a "limited-use liquid oil-fired" if (1) the EGU meets the final definitions of "oil-fired electric utility steam generating unit" and "fossil fuel-fired;" and (2) has an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing.

E. What are the requirements during periods of startup, shutdown, and malfunction?

As discussed below in section VI.E., for startup and shutdown, the requirements have changed since proposal. For periods of startup and shutdown, the EPA is finalizing work practice standards in lieu of numeric emission limits. Numeric emission limits apply for all other periods for all pollutants, except organic HAP. For malfunctions, the EPA is finalizing an affirmative defense for exceedances of the numerical emission limits that are caused by malfunctions.

F. What are the testing and initial compliance requirements?

We are requiring that you, as an owner or operator of a new or existing coal- or oil-fired EGU, must conduct performance tests to demonstrate compliance with all applicable emission limits. For units using certified continuous emissions monitoring systems (CEMS) that directly measure the regulated pollutant under final 40 CFR part 63, subpart UUUUU (*e.g.*, Hg CEMS, HCl CEMS, HF CEMS, SO_2 CEMS (where an SO_2 limit applies as the alternative equivalent standard)), or sorbent trap monitoring systems, the initial performance test consists of all valid data recorded with the certified monitoring system in the first 30 boiler operating days of data collected with the certified monitoring system prior to the initial compliance demonstration date specified in § 63.10005. A source may also elect to use a PM CEMS to demonstrate compliance with the filterable PM emission limit. If this option is selected, then the same provisions as noted above for other CEMS will apply. (Note that EPA anticipates that the PM monitoring device that may most often will be used is a PM continuous parameter monitoring system (CPMS) in conjunction with an operating limit, as more fully described below.) For units and pollutants not being monitored via CEMS, the owner or operator of an affected unit must perform the initial performance testing in accordance with established EPA reference test methods or the voluntary consensus standard methods incorporated by reference. You, as the owner or operator of an affected unit, must conduct the following compliance tests where applicable:

(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, if you elect to comply with the filterable PM emission limit, you must conduct filterable PM emissions testing using EPA Method 5 from Appendix A to part 60 of chapter 40 to determine initial compliance. Alternatively, if you elect to comply with the total non-mercury HAP metals emission limit or the individual non-mercury HAP metals emissions limits, you must conduct HAP metals testing using EPA Method 29 from Appendix A to part 60 of chapter 40. Note for this rule that the filter temperature for each Method 5 or 29 emissions test must be maintained at 160° ± 14 °C (320 ° ± 25 °F), and the material in Method 29 impingers must be analyzed for metals content. Whenever metals testing is performed with Method 29, you must report the front half and back half analytical fractions separately.

(2) For coal-fired, IGCC, and solid oil-derived fuel-fired units, you must use a Hg CEMS or a sorbent trap monitoring system for both initial compliance and continuous compliance using the continuous Hg monitoring provisions of Appendix A to 40 CFR part 63, subpart UUUUU, except where the low emitting EGU (LEE) requirements apply (see below). The initial performance test consists of all valid data recorded with the certified Hg monitoring system in the 30 boiler operating days of data collected with the certified monitoring system by the initial compliance demonstration date specified in § 63.10005.

(3) For coal-fired and solid oil-derived fuel-fired units and new or reconstructed IGCC units that employ FGD technology and elect to meet the alternative SO_2 limit in place of the HCl limit, you need not conduct an initial stack test for HCl or SO_2. Instead, the 30 boiler operating days of data collected with the certified SO_2 CEMS by the initial compliance demonstration date specified in § 63.10005 are used to determine initial compliance, and the SO_2 CEMS is used thereafter to demonstrate continuous compliance. If you instead opt to meet the HCl limit and use an HCl CEMS for compliance, you need not conduct an initial stack test for HCl. Instead, the 30 boiler operating days of data collected with the certified HCl CEMS by the initial compliance demonstration date specified in § 63.10005 are used to determine initial compliance. For units not using the SO_2 or HCl CEMS options, you must conduct an initial stack test for HCl using EPA Method 26, 26A, or 320 from Appendix A to part 60 of chapter 40. You may use EPA Method 26 or 320 or ASTM Method D6348–03 (Reapproved 2010) with additional quality assurance if no entrained water droplets exist in the exhaust gas, but you must use Method 26A if entrained water droplets exist in the exhaust gas.

(4) For liquid oil-fired units, you must conduct initial performance testing as follows. If you elect to meet the filterable PM limit instead of the non-mercury metals limit (total or individual), then use Method 5 with the filter material maintained at 160° ± 14°C (320° ± 25°F). Alternatively, you may use a PM CEMS as discussed elsewhere in this preamble. If you elect to meet either the total or individual HAP metals limit, you will use Method 29 for all non-mercury HAP metals. For Hg, conduct emissions testing using EPA Method 29 or 30B from Appendix A to part 60 of chapter 40, or ASTM Method D6784–02 (Reapproved 2008). For acid gases, conduct HCl and HF testing using EPA Method 26A, 320, or 26; or you may elect to comply by using an HCl CEMS and/or an HF CEMS; or under certain conditions you may choose to demonstrate compliance by measuring fuel moisture to demonstrate that moisture content is no greater than 1.0 percent. You must measure daily if fuel is delivered continuously or per shipment if fuel is delivered on a batch basis, or you may use a fuel moisture content certification provided by your fuel supplier. If you use a CEMS, then use the 30 boiler operating days of data collected with the certified monitoring system by the initial compliance demonstration date specified in § 63.10005 to determine initial compliance.

(5) For the required performance stack tests, if you are demonstrating compliance with a heat-input based standard, you must conduct concurrent O_2 or carbon dioxide (CO_2) emission testing using EPA Method 3A or 3B from appendix A to part 60 of chapter 40 or ANSI/ASME PTC 19.10–1981 and then use an appropriate equation, selected from among Equations 19–1

through 19–9 in EPA Method 19 from appendix A to part 60 of chapter 40, to convert measured pollutant concentrations to lb/MMBtu values. Multiply the lb/MMBtu value by one million to get the lb/TBtu value (where applicable). If you choose to meet an electrical output-based emissions limit, you must also collect concurrent stack gas flow rate and electrical production data.

(6) For an existing unit that you believe will qualify as LEE for Hg, you must conduct an initial Method 30B test over 30 days and follow the calculation procedures in the final rule to document a potential to emit less than 10 percent of the applicable Hg emissions limit or less than 29 pounds of Hg per year. If your unit qualifies as a LEE for Hg, you must conduct subsequent performance tests on an annual basis to demonstrate that the unit continues to qualify. For all other pollutants, you must conduct the initial compliance test, and then all other required tests over a 3-year period, and in all such tests, your emission results must be less than 50 percent of the applicable emission limit. If you qualify as a LEE on that basis, you must conduct subsequent performance tests every 3 years to demonstrate that the unit continues to qualify.

(7) You may use results from tests conducted no earlier than 12 months before the compliance date of this rule as the initial performance test for an applicable pollutant, provided that:

a. You certify and keep records demonstrating that no significant changes have occurred,

b. Tests were conducted using methods allowed in this rule in accordance with § 63.10007 and Table 5,

c. You have records of all parameters needed to convert results to units of the standard for the entire period, and

d. For a CEMS-based performance test, you have all the required data for the entire 30-boiler operating day rolling average period.

Operating Limit for PM CEMS

Under the final rule, you may elect to comply continuously with an operating limit, established during the initial performance test, to demonstrate continuous compliance with the filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals limit. You will use a PM CPMS to monitor compliance with the operating limit. The PM CPMS operating principle must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal. Meeting the operating limit serves as your demonstration of continuous compliance with the filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals limit. As mentioned earlier, if you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals. As noted below, when you use this operating limit, you can reduce stack testing frequency to demonstrate ongoing compliance. You may also opt to install and operate a PM CEMS certified in accordance with Performance Specification 11 and Procedure 2 of 40 CFR part 60, Appendices B and F, respectively. If you elect to use this option, then the requirements for quarterly testing with Method 5, or annual testing and use of a PM CPMS, are no longer applicable.

Dioxins/Furans and Non-Dioxin/Furan Organic HAP

For dioxins and furans and non-dioxin/furan organic HAP, you must submit documentation that you have conducted a combustion process tune-up, a thorough equipment inspection, and an optimization to minimize generation of CO and NO_X, all meeting the requirements of this final rule. The work practice standard involves maintaining and inspecting the burners and associated combustion controls, tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. You must collect CO and NO_X data and may use portable analyzers (which include handheld or similar devices) to monitor and verify the results. The specific details are addressed in 40 CFR 63.10021 of the final rule.

This same work practice standard also applies in place of any emission limits for Hg, non-mercury metals HAP, acid gas HAP, dioxins and furans, and non-dioxin/furan organic HAP from a limited-use, liquid oil-fired EGU (*i.e.*, a unit that has an annual capacity factor on oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater). The EPA established this subcategory in response to comments and a further analysis of the units within this subcategory in the ICR database. For these units, EPA believes that the required work practice standards are appropriate and consistent with the requirement of CAA section 112(h).

G. What are the continuous compliance requirements?

To demonstrate continuous compliance with the emission limitations, the final rule includes the following requirements:

(1) *Use of CEMS.* Where a CEMS or a sorbent trap monitoring system is used for demonstrating initial compliance, you also must use the CEMS or sorbent trap monitoring system on a continuous basis to demonstrate ongoing compliance with the numerical emission limits. CEMS or sorbent trap monitoring system data are not used to determine compliance with the work practice standards applicable during periods of startup and shutdown, but sources that install a CEMS or a sorbent trap monitoring system to demonstrate compliance with the numerical emission limits must operate the system at all times, as EPA intends to evaluate the continuous monitoring data from start-up and shutdown periods as discussed below. You must calculate a rolling average for each successive 30-boiler operating day rolling average period. All valid data collected during each successive period will be used to demonstrate compliance, except for data collected during periods of startup and shutdown; during those periods, the owner or operator must meet work practice requirements instead of the numerical emission limits. There is no numerical minimum data availability required to constitute a valid 30-boiler operating day rolling average; however, you must monitor at all times that the process is in operation (including during startups and shutdowns, although emissions during these periods are not included in the 30-boiler operating day average). You must operate, maintain, and quality-assure the CEMS or sorbent trap monitoring systems in accordance with the provisions in 40 CFR 63.10010 and Appendix A and B of the final rule (for Hg, HCl, and HF CEMS), in accordance with Performance Specification 11 in Appendix B to 40 CFR part 60 and Procedure 2 in Appendix F to part 60 (for PM CEMS used for direct compliance), or in accordance with 40 CFR part 75 (for SO_2 CEMS, and certain ancillary monitors such as a diluent or moisture monitor).

For each unit using HCl, HF, SO_2, PM, or Hg CEMS or a sorbent trap monitoring system for continuous compliance, you must install, certify, maintain, operate and quality-assure the

additional CEMS (*e.g.*, CEMS that measure O_2 or CO_2 concentration, stack gas flow rate, and, if default moisture values are not used, moisture content) needed to convert pollutant concentrations to units of the emission standards or operating limits. Where appropriate, you must certify and quality-assure these additional CEMS according to 40 CFR part 75.

For HCl and HF CEMS, the EPA is adding monitoring provisions as Appendix B to 40 CFR part 63, subpart UUUUU. Appendix A references performance specification (PS) 15 of Appendix B to 40 CFR part 60 for Fourier Transform Infrared (FTIR) CEMS for procedures to certify and conduct ongoing quality assurance on these FTIR CEMS. In addition, we expect to publish a PS specific to HCl CEMS in the near future (prior to the compliance date of this rule). In the meantime, you may petition the Administrator under the procedure given in 40 CFR 63.7(f) for an alternative approach to compliance monitoring or testing for HCl or any other regulated pollutant.

When using a sorbent trap monitoring system, you may use each pair of sorbent traps to collect Hg samples for no more than 15 boiler operating days. Under the general duty to monitor at all times, you must replace traps in a timely manner to ensure that Hg emissions are sampled continuously.

For Hg monitoring, the EPA is adding Hg monitoring provisions as Appendix A to 40 CFR part 63, subpart UUUUU, and requiring use of these provisions to document continuous compliance with the rule for coal-fired, IGCC, and solid oil derived-fired units that cannot qualify as LEEs. Appendix A consolidates all Hg monitoring provisions.

Today's rule provides two basic Hg continuous monitoring options: Hg CEMS and sorbent trap monitoring systems. Appendix A requires initial certification and periodic quality assurance (QA) testing of the Hg CEMS and sorbent trap monitoring systems. The certification tests required for the Hg CEMS are a 7-day calibration error test; a linearity check, using NIST-traceable elemental Hg standards; a 3-level system integrity check (similar to a linearity check), using NIST-traceable oxidized Hg standards; a cycle time test; and a relative accuracy test audit (RATA). Table A–1 of Appendix A summarizes the performance specifications for the required certification tests. For ongoing QA of the Hg CEMS, Appendix A requires daily calibrations, weekly single-point system integrity checks, quarterly linearity checks (or 3-level system integrity checks), and annual RATAs. Table A–2 in Appendix A summarizes these ongoing QA test requirements and the applicable performance criteria for Hg CEMS, which are consistent with those published in support of CAMR and are, thus, familiar to the industry.

For sorbent trap monitoring systems, a RATA is required for initial certification, and annual RATAs are required for ongoing QA. The performance specification for these RATAs is the same as for the RATAs of the Hg CEMS. Bias adjustment of the measured Hg concentration data is not required. For day-to-day operation of the sorbent trap system, Appendix A requires you to follow the procedures and QA/QC criteria in PS 12B in Appendix B to 40 CFR part 60. PS 12B is nearly identical to the Appendix K to 40 CFR part 75, published in support of CAMR and with which the industry is familiar. The 40 CFR part 75 concepts of:

a. Determining the due dates for certain QA tests on the basis of "QA operating quarters" and

b. Grace periods for certain QA tests apply to both Hg CEMS and sorbent trap monitoring systems. Mercury concentrations measured by Hg CEMS or sorbent trap systems are used together with hourly flow rate, diluent gas, moisture, and electrical load data, to express the Hg emissions in units of the rule, on an hourly basis (*i.e.*, lb/TBtu or lb/GWh). Section 6 of Appendix A provides the necessary equations for these unit conversions.

For HCl and HF CEMS, the EPA is adding monitoring provisions as Appendix B to 40 CFR part 63, Subpart UUUUU. Appendix A references performance specification (PS) 15 of Appendix B to 40 CFR part 60 for Fourier Transform Infrared (FTIR) CEMS for procedures to certify and conduct ongoing quality assurance on these FTIR CEMS. In addition, we expect to promulgate a generic PS specific to HCl CEMS prior to the compliance date of this rule. In the meantime, you may petition the Administrator under the procedure given in 40 CFR 63.7(f) for an alternative approach to compliance monitoring or testing for HCl or any other regulated pollutant.

(2) *Use of stack tests.* If you demonstrate initial compliance on the basis of a stack test, you must demonstrate continuous compliance by conducting periodic stack tests on a quarterly basis. This includes filterable PM (or non-mercury HAP metals) and HCl from coal-fired and solid oil-derived fuel-fired EGUs, and filterable PM (or HAP metals) and HCl and HF from liquid oil-fired EGUs with the following exceptions:

a. If you use a PM CPMS and associated operating limit, you may conduct the applicable Method 5 or Method 29 test once annually rather than quarterly, in which case you must re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule includes basic quality checks that the PM CPMS must meet and a requirement for you to develop and follow a site-specific monitoring plan to be approved by the delegated authority. You must demonstrate compliance with the operating limit by using all valid hourly data collected during each successive 30-boiler operating day period rolled daily. The 30-boiler operating day rolling average is calculated by all of the valid hourly average PM CPMS output values collected for the 30 boiler operating days (excluding hours of startup and shutdown; *see* section V.E. of this preamble).

b. If you combust liquid fuels and if your fuel moisture content is no greater than 1.0 percent, you may demonstrate ongoing compliance with HCl and HF emissions limits by:

i. Measuring fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis;

ii. Measuring fuel moisture content daily if your fuel arrives on a continuous basis; or

iii. Obtaining and maintaining a fuel moisture certification from your fuel supplier.

Should the moisture in your liquid fuel be more than 1.0 percent, you must

i. Conduct HCl and HF emissions testing quarterly and establish site-specific monitoring to demonstrate continued acid gas control performance between periodic tests, or

ii. Use an HCl CEMS and/or HF CEMS.

c. If your existing unit qualifies as an LEE for Hg, you must conduct another 30-day Method 30B performance test on your unit once per year to reestablish that the unit continues to qualify as a LEE for Hg. If the results of the LEE test show that the unit exceeds 10 percent of the emissions limit or exceeds the potential to emit 29 pounds of Hg per year, you will lose LEE status for the unit. You can regain LEE status for that unit if every required performance test for a 3-year period shows that emissions from the unit did not exceed the LEE limit. If LEE status is lost for a solid fuel unit, you must commence quarterly performance testing until you install,

certify, and operate a Hg CEMS or a sorbent trap monitoring system, and you must complete the installation and certification within 6 months of losing LEE status; for a liquid fuel unit, you must commence quarterly performance testing.

d. If a liquid oil-fired EGU has an annual capacity factor on oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, you must demonstrate continuous compliance with the applicable work practice standard by conducting at least once every 36 calendar months (48 calendar months if a neural network is employed) a combustion process tune-up, a thorough equipment inspection, and an optimization to minimize generation of CO and NO_X, all meeting the requirements of this final rule. You must maintain and inspect the burners and associated combustion controls, tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. You must collect CO and NO_X data using portable analyzers (which typically include handheld or similar devices). Specific details are addressed in 40 CFR 63.10021 of the final rule. In addition, you must record boiler operating hours, by fuel type, in each calendar quarter.

e. The rule allows a grant of LEE status to existing units with test results that show a history of low, non-mercury emissions. As mentioned earlier, LEE status reduces testing frequency for units. After a 3-year period during which every emissions test for a specific pollutant shows emissions no greater than 50 percent of the emissions limit, you may reduce the emissions testing frequency for that specific non-mercury pollutant to once every 36 months. If any subsequent emissions test for that pollutant exhibits emissions greater than 50 percent of the emissions limit, you must revert to the original emissions testing frequency until you re-establish a 3-year period of very low emissions no greater than 50 percent of the standard.

f. For liquid oil-fired units that demonstrate continuous compliance with quarterly performance tests for HCl and HF emission limits rather than through use of HCl and HF CEMS, the final rule requires a site-specific monitoring plan in addition to the quarterly tests. For these pollutants, there is unlikely to be any existing underlying monitoring (such as compliance assurance monitoring) that serves as an additional tool to ensure the source's operations remain consistent with operating conditions during a recent successful performance test. The requirement for a site-specific monitoring plan fills this gap and ensures that in between tests, the source continues to operate in a manner designed to maintain HCl and HF emissions in compliance with the emission limits under this rule. The appropriate parameters to monitor will depend on the compliance strategy employed by a specific source, and thus EPA is enabling the monitoring approach to be established on a case-by-case basis. Given the relatively small number of these units and the other compliance options available, we anticipate that this approach will apply to a small set of units. The monitoring plan will identify the parameters monitored, the monitoring methods, the QA/QC elements that apply, and the data reduction elements (including appropriate averaging periods, as applicable). See 40 CFR 63.10000(c)(2)(ii).

(3) *Work practice standard.* For the performance tune-up work practice requirements, you must demonstrate continuous compliance by conducting the work practice at least once every 36 calendar months (48 calendar months if a neural network is employed). The work practice involves maintaining and inspecting the burners and associated combustion controls, tuning the specific burner type, as applicable, to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. A combustion tune-up will involve optimizing combustion of the unit consistent with manufacturer's instruction as applicable, or in accordance with best combustion engineering practice for that burner type.

H. What are the notification, recordkeeping and reporting requirements?

All new and existing sources in all subcategories must comply with certain requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 9 of this final rule. The General Provisions include specific requirements for notifications, recordkeeping, and reporting. You must submit a notification of compliance status report for each unit, according to the schedule required by 40 CFR 63.9(h) of the General Provisions, including a certification of compliance.

Except for units that use CEMS for continuous compliance, under this rule you must provide semiannual compliance reports, as required by 40 CFR 63.10(e)(3) of subpart A, that indicate whether a deviation from any of the requirements in the rule occurred and whether or not any process changes occurred and compliance certifications were reevaluated. As discussed below, we are finalizing a requirement to use the 40 CFR part 75-based Emissions Collection and Monitoring Plan System (ECMPS) for reporting emissions and related data for units using CEMS for most pollutants. Also, as discussed below, for the PM CPMS, PM CEMS, and performance test results, we require you to use EPA's WebFIRE [309] database for reporting.

This rule requires you to keep certain records to demonstrate compliance with each emission limit and work practice standard. The General Provisions to 40 CFR part 63 specify these recordkeeping requirements (see Table 9 to this subpart). Among other specific records, you must keep the following:

(1) All reports and notifications submitted to comply with this rule.

(2) Continuous monitoring data as required in this rule.

(3) Each instance in which you did not meet an emission limit, work practice requirement, operating limit, or other compliance obligation (*i.e.*, deviations from this rule).

(4) Daily hours of operation by each unit.

(5) As part of the general duty to keep all monitoring data, fuel moisture content of liquid fuel, if you elect to demonstrate compliance using that information.

(6) A copy of the results of all performance tests, monitor certifications, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with this rule.

(7) A copy of your site-specific performance evaluation test plans developed for this rule as specified in 40 CFR 63.8(e), if applicable.

(8) A copy of your acid gas control system parameter monitoring plan under 40 CFR 63.10000(c)(2)(ii).

You also must submit the following additional notifications:

(1) Notifications required by the General Provisions.

(2) Initial Notification no later than 120 calendar days after you become subject to this subpart.

[309] WebFIRE is the Internet version of FIRE. The Factor Information Retrieval (FIRE) Data System is a database management system containing EPA's recommended emission estimation factors for criteria and HAP. It includes information about industries and their emitting processes, the chemicals emitted, and the emission factors themselves.

(3) Notification of Intent to conduct performance tests and/or compliance demonstration at least 60 calendar days before the performance test and/or compliance demonstration is scheduled.

(4) Notification of Compliance Status 60 calendar days following completion of the performance test and/or compliance demonstration.

Electronic reporting is becoming a common element of modern life (as evidenced by electronic banking and income tax filing), and the EPA is beginning to require electronic submittal of environmental data. Electronic reporting is already common in environmental data collection and many media offices at EPA are reducing reporting burden for the regulated community by embracing electronic reporting systems as an alternative to paper-based reporting.

One of the major benefits of reporting electronically is standardization, to the extent possible, of the data reporting formats that provides more certainty to users of what data are required in specific reports. For example, electronic reporting software allows for more efficient data submittal and the software's validation mechanism helps industry users submit fewer incomplete reports. This alone saves industry report processing resources and reduces transaction times. Standardization also allows for development of efficient methods to compile and store much of the documentation required to be reported by this rule.

Use of Electronic Reporting System

We are requiring that you submit certain reports electronically. In addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with these reports will save industry, state, local, tribal agencies, the public, and the EPA significant time, money, and effort while also improving the transparency and quality of emission inventories and, as a result, air quality regulations.

The reports to be submitted electronically include all performance test reports, notification of compliance status reports, compliance, and continuous monitoring data summaries specified in 40 CFR 63.10031 of this rule. Performance tests are required to be conducted as described in 40 CFR 63.7 of the General Provisions. The data that must be submitted as the performance test report are also described in 40 CFR 63.7. These data must be submitted (except in limited cases) to EPA's WebFIRE database by using the electronic reporting tool (ERT) and the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX), as described below. The data requirements for the notification of compliance status and compliance reports are described in detail in the regulatory text (40 CFR 63.10031) of this rule, but they essentially mirror the requirements in 40 CFR 63.6 of the General Provisions. These reports will also be submitted to WebFIRE using an electronic form found in CEDRI and through the CDX as described below. As required in 40 CFR 63.10031(f)(2) of the final rule, the continuous monitoring summaries are required to be submitted quarterly. The quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the PM CPMS. These reports will also be submitted to WebFIRE using an electronic form found in CEDRI and through the CDX, as described below. This same approach will apply if a source elects to use a PM CEMS or receives approval to use a HAP metals CEMS as an alternative monitoring method.

The availability of electronic reporting for sources subject to the Subpart UUUUU will provide efficiency, improved services, better accessibility of information, and more transparency and accountability. Additionally, submittal of these required reports electronically provides significant benefits for regulatory agencies, industry, and the public. The compliance data electronic reporting system (CEDRI and CDX) is being developed such that once a facility's initial data entry into the system is established and a report is generated, subsequent data submittal will only consist of electronic updates to existing information in the system. Such a system will effectively reduce the burden associated with submittal of data and reports by reducing the time, costs, and effort required to submit and update hard copies of documentation. State, local, and tribal air pollution control agencies will also benefit from having access to the more streamlined and accurate electronic data submitted to the EPA. Electronic reporting will allow for an electronic review process rather than a manual data assessment, making review and evaluation of the source-provided data and calculations easier and more efficient. Electronic reporting will also benefit the public by generating a more transparent review process and increasing the ease and efficiency of data accessibility. Furthermore, electronic reporting will reduce the burden on the regulated community by reducing the effort involved in data collection and reporting activities. In the future, we anticipate there will be fewer and less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. Electronic reporting will substantially reduce this burden, because the EPA will already have these data available and consolidated in an electronic database named WebFIRE. We anticipate that using electronic reporting for the required reports will result in an overall reduction in reporting costs; for a discussion of the economic and cost impacts of electronic reporting, see section XII.D. of this preamble.

Another benefit of electronic data submittal is that these data will greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA will be able to ensure that emission factors, when updated, represent the most current range of operational practices.

Data entry of these electronic reports will be through the CEDRI that is accessed through EPA's CDX (*www.epa.gov/cdx*). Data submitted electronically through CEDRI will be stored in CDX as an official copy of record.

Once you have accessed CEDRI, you will select the applicable subpart for the report that you are submitting. You will then select the report being submitted, enter the data into the form, and click on the submit button. In some cases, such as with submittal of a notification of compliance status report, you will select the report icon, enter basic facility information, and then upload the report in a specified file format.

In addition, we believe that there will be value in allowing other reporting forms to be developed and used in cases where the other reporting forms can provide an alternate electronic file consistent with EPA's form output format. This approach has been used successfully to provide alternatives for other electronic forms (*e.g.*, income tax submittal).

In cases where performance test data are to be submitted to the EPA, you must enter the performance test data

and information into the electronic reporting tool (ERT) which can be accessed at *http://www.epa.gov/ttn/chief/ert/index.html.* In CEDRI, the user must then upload the ERT file. CEDRI submits a copy of the ERT project data file directly to WebFIRE where the data are made available. Where performance test reports are submitted, WebFIRE notifies the appropriate state, local, or tribal agency contact that an ERT project data file was received from the source.

Submitting performance test data electronically to the EPA will apply only to those performance tests conducted using test methods that will be supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at the ERT Web site listed above.

I. Submission of Emissions Test Results to the EPA

The EPA has determined that harmonization of the monitoring and reporting requirements of this final rule with 40 CFR part 75 is appropriate, where the affected industry already has a well-defined system for continuous monitoring and reporting of emissions under that part. Therefore, the Agency is finalizing monitoring and reporting requirements for most CEMS that are consistent with 40 CFR part 75. You must report CEMS data (other than PM CEMS data or data from alternative monitoring subject to site-specific approval such as a HAP metals CEMS) to the EPA electronically, on a quarterly basis, using the ECMPS.

The ECMPS process divides electronic data into three categories, the first of which is monitoring plan data. You must maintain the electronic monitoring plan separately and can update it at any time if necessary. The monitoring plan documents the characteristics of the affected units (*e.g.*, unit type, rated heat input capacity, etc.) and the monitoring methodology used for each parameter (*e.g.*, CEMS). The monitoring plan also describes the type of monitoring equipment used (hardware and software components), includes analyzer span and range settings, and provides other useful information. Nearly all coal-fired EGUs are subject to the ARP and thus have established electronic monitoring plans that describe their required SO_2, flow rate, CO_2 or O_2, and, in some cases, moisture monitoring systems. The EPA will adjust the ECMPS monitoring plan format to accommodate this same type of information for Hg, HCl, and HF CEMS, with the addition of a few codes for the new parameters.

The second type of data collected through ECMPS is certification and QA test data. These data include data from linearity checks, RATAs, cycle time tests, 7-day calibration error tests, and a number of other QA tests that are required to validate the emissions data. You may submit the results of these tests to the EPA as soon as you obtain the results, with one notable exception. Daily calibration error tests are not treated as individual QA tests, due to the large number of records generated each quarter. Rather, these tests must be included in the quarterly electronic reports, along with the hourly emissions data. The ECMPS system is set up to receive and process certification and QA data from SO_2, CO_2, O_2, flow rate, and moisture monitoring systems that are installed, certified, maintained, operated, and quality-assured according to 40 CFR part 75. EGUs routinely submit these data to the EPA under the ARP and other emissions trading programs.

To accommodate the certification and QA tests for Hg CEMS, other CEMS, and sorbent trap monitoring systems, the structure and functionality of ECMPS needs relatively few changes, because most of the tests are the same as those required for other gas monitors. For reporting Hg, HCl, SO_2, and HF CEMS data under this rule, we are disabling ECMPS' 40 CFR part 75 bias test (which is required for certain types of monitors under the EPA's SO_2 and NO_x emissions trading programs). The bias adjustment of the data from these monitors is unnecessary for compliance with the rule.

The third type of data collected through ECMPS is the hourly emissions data, which, as previously noted, is reported on a quarterly schedule. You must submit reports within 30 days after the end of each calendar quarter. The emissions data format requires hourly reporting of all measured and calculated emissions values, in a standardized electronic format. You must report direct measurements made with CEMS, such as gas concentrations, in a Monitor Hourly Value (MHV) record. A typical MHV record for gas concentration includes data fields for:

(1) The parameter monitored (*e.g.*, SO_2);

(2) The unadjusted and bias-adjusted hourly concentration values (note that if bias adjustment is not required, only the unadjusted hourly value is reported);

(3) The source of the data, *i.e.*, a code indicating either that each reported hourly concentration is a quality assured value from a primary or backup monitor, or that quality-assured data were not obtained for the hour; and

(4) The percent monitor availability (PMA), which is updated hour-by-hour. This generic record structure could easily accommodate hourly average measurements from CEMS used under this rule.

The ECMPS reporting structure is quite flexible, which makes it useful for assessing compliance with various emission limits. The Derived Hourly Value (DHV) record allows calculations of a wide variety of quantities from the reported hourly emissions data. For instance, if an emission limit is expressed in units of lb/MMBtu, the DHV record can be used to report hourly pollutant concentration values in these units of measure, since the lb/MMBtu values can be derived from the hourly pollutant and diluent gas (CO_2 or O_2) concentrations reported in the MHV records. The ECMPS can also accommodate multiple DHV records for a given hour in which more than one derived value is required to be reported. The system will support reporting hourly data in the units of the emission standards (*e.g.*, lb/MMBtu, lb/TBtu, lb/GWh, etc.) when hourly Hg concentration data are reported through ECMPS using the DHV record, in conjunction with the appropriate equations and auxiliary information such as heat input and electrical load (all of which are reported hourly in the emissions reports).

One change in this rule from standard 40 CFR part 75 emissions data reporting is elimination of the requirement to provide substitute data calculations within ECMPS. The ARP and other emissions trading programs that report emissions data to the EPA using 40 CFR part 75 require provision of a complete data record. Emissions data are required to be reported for every unit operating hour. When CEMS are out of service, substitute data must be reported to fill in the gaps. However, for the purposes of compliance with a NESHAP, reporting substitute data during monitor outages is not necessary, as quantification of total mass emissions is not the focus of the rule. Hours when a monitoring system is out of service would be counted as hours of monitor down-time and may be a deviation from the monitoring requirements of this rule unless the rule provides an exception, as it does for routine quality control and maintenance activities.

In contrast to the CEMS-related data that would be submitted through ECMPS, you must submit reports of performance tests and PM CPMS data to EPA's WebFIRE database by using CEDRI that is accessed through EPA's

CDX (*www.epa.gov/cdx*). You must submit performance test data in the file format generated through use of EPA's ERT (see *http://www.epa.gov/ttn/chief/ert/index.html*) within 60 days of performance test completion. Electronic data submittal requirements are described in section V.H. of this preamble.

Other notifications and reports not currently accepted by the electronic reporting system will be submitted in hardcopy form at this time.

VI. Summary of Significant Changes Since Proposal

The previous section described the requirements that EPA is finalizing in this rule. This section will discuss in greater detail the key changes EPA is making from the proposed. These changes result from EPA's review of the additional data and information provided to us and our consideration of the many substantive and thoughtful comments submitted on the proposal. While our approach and methodology to establishing the standards remain the same, the changes make the final rule more flexible and cost-effective, reduce reliability concerns and improve clarity, while fully preserving, or improving, the public health and environmental protection required by the CAA.

A. Applicability

Since proposal, the EPA has made certain changes to the applicability provisions of the final rule to provide clarity. These changes do not change the universe of sources subject to the rule.

The EPA is revising a number of the proposed definitions and adding a definition for "natural gas-fired electric utility steam generating unit" in the final rule to provide clarity to the regulated community concerning the standards applicable to coal- and oil-fired EGUs.

In the proposed rule, the EPA defined "[e]lectric utility steam generating unit" consistent with the CAA section 112(a)(8) definition:

> A fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

40 CFR 63.10042.

We also indicated how we would determine whether units were coal-fired or oil-fired fired EGUs: "If an EGU burns coal (either as a primary fuel or as a supplementary fuel), or any combination of coal with another fuel (except solid waste as noted below), the unit is considered to be coal fired under this proposed rule. If a unit is not a coal-fired unit and burns only oil, or oil in combination with another fuel other than coal (except as noted below), the unit is considered to be oil fired under this proposed rule." 76 FR 25020.

We proposed a definition for the term "fossil fuel-fired" because that term was not defined in the statute and we wanted to clarify the level of fossil fuel combustion necessary to satisfy the CAA section 112(a)(8) definition of EGU. The definition focused on coal and oil combustion because the EPA was only regulating coal- and oil-fired EGUs in this final rule. The proposed definition contained two primary elements: (1) the unit must be capable of combusting sufficient amounts of coal or oil to generate the equivalent of 25 megawatts electrical output; and (2) the unit must have fired coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years. 76 FR 25025. We further stated that for a unit to be "capable of combusting" coal or oil the unit must have a permit that authorized the combustion of coal or oil and also have the appropriate fuel handling facilities on-site. *Id.*

As explained in the proposed rule, natural gas-fired EGUs were not included in the December 2000 listing so such units that otherwise met the CAA section 112(a)(8) definition of EGU because of natural gas combustion are not subject to the final rule. In the proposed rule, we stated that an EGU that "combusts natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous 3 calendar years or 85.0 percent or more of the annual heat input during any one of those calendar years" was not subject to the rule. *Id.* The references to 90 percent natural gas combustion over 3 years and 85 percent natural gas combustion in any one year were included to align with the definitions of "fossil fuel-fired" so that it would be clear that units combusting primarily natural gas would not be considered coal-fired, oil-fired, or IGCC EGUs if they burned 10 percent or less of coal, oil, or synthetic gas derived from coal or solid oil over 3 years or 15 percent or less of such fuels in any one year. We did not intend to suggest that to be considered a fossil fuel-fired EGU a natural gas-fired unit that is not a coal-fired or oil-fired EGU would have to combust natural gas that exceeded the 10 percent/15 percent thresholds set forth in the proposed rule. In fact, in 40 CFR 63.9983 of the proposed rule, we stated that "[a]ny EGU that is not a coal- or oil-fired EGU and combusts natural gas more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years" is not subject to this subpart.

We further explained that the percentages included in the definition of "fossil fuel-fired" would prevent units that primarily combusted fuels other than fossil fuels from being subjected to the final rule:

> Units that do not meet the definition of fossil-fuel fired would, in most cases, be considered IB units subject to one of the Boiler NESHAP. Thus, for example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.*, less than or equal to 250 MMBtu/hr and used less than 10.0 percent of the average annual heat input during the previous 3 calendar years or less than 15.0 percent of the annual heat input during any one of those calendar years) is not considered to be a fossil fuel-fired EGU under this proposed rule. The EPA has based its threshold value on the definition of "oil-fired" in the ARP found at 40 CFR 72.2. As EPA has no data on such use for (*e.g.*) biomass co-fired EGUs because their use has not yet become commonplace, we believe this definition also accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this proposed rule. *Id.*

Thus, in the proposed rule, we intended to create thresholds to determine when a unit is fossil fuel-fired and for which fossil fuel the unit is fossil fuel-fired. We intended to include a unit combusting more than the defined amount of coal in one of the coal-fired EGU subcategories. If a unit is not coal-fired and it is combusting more than the defined amount of oil, we intended to include the unit in one of the oil-fired EGU subcategories. We also intended to make clear that EGUs that are neither coal-fired nor oil-fired but combust more than the defined amount of natural gas are natural gas-fired EGUs not subject to the final standards. However, the definitions, as proposed, were not sufficiently descriptive.

For example, we included a definition for "coal-fired electric utility steam generating unit" that did not include the requirement that the unit must combust coal for at least 10 percent of the heat input over 3 years or 15 percent of the heat input in any one year. Instead, in the proposed rule we indicated that a unit was coal-fired if it burned coal in any amount. We did not intend to

define a unit as coal-fired if it burned coal that accounted for 10 percent or less over 3 years or 15 percent of less in any one year, as that would be inconsistent with the definition of fossil fuel-fired and the definitions for the oil-fired EGU subcategories. Under the proposed rule construct, a unit that combusts mostly biomass and less than 10 percent coal over 3 years would not be a coal-fired EGU because it would not meet the "fossil fuel-fired" definition. But a unit burning mostly petroleum coke and less than 10 percent coal over 3 years might be considered a coal-fired EGU because it would meet the definition of "fossil fuel-fired" and be burning some coal, even though that level of coal combustion alone would not be sufficient to make the unit "fossil fuel-fired" for coal. That result is at odds with our intent. The same would hold true for an EGU that combusts mostly natural gas and less than 10 percent synthetic gas derived from coal over a 3-year period. Our proposal preamble makes clear that we did not intend this result because we specifically stated that units burning 90 percent or more natural gas over a 3-year period would be considered natural-gas fired EGUs. 76 FR 25025.

In addition, we proposed to define "[u]nit designed to burn solid oil fuel subcategory" to include any EGU that burned a solid fuel derived from oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, either alone or in combination with other fuels. We also included the 10 percent/15 percent thresholds in the definition for the liquid oil subcategory, but, as stated above, we did not include the thresholds in the definition of "coal-fired" EGU. Therefore, there would be some confusion for a source that blended coal with solid oil derived fuel (*e.g.*, petroleum coke). For example, the owner or operator of an EGU that burned sufficient solid oil-derived fuel that accounted for 80 percent of the heat input in a given year and the remainder of the fuel was coal would not be sure which standard applied because the definitions in the proposed rule were internally inconsistent.

For these reasons, we are revising the definitions for "coal-fired electric utility steam generating unit," "integrated gasification combined cycle electric utility steam generating unit," and "oil-fired electric utility steam generating unit," and we are adding a definition of "natural-gas fired electric utility steam generating unit" as set out in 40 CFR 63.10042.

In addition to these changes, we are revising the definition of "fossil fuel-fired" based on comments. We are revising the definition to remove the heat input equivalent of 25 MW because commenters noted that the equivalency used (taken from 40 CFR part 60, subpart Da) could not be applied consistently because of differing boiler efficiencies. Commenters noted that owners/operators were familiar with the use of the "MW" term for the boilers and boilers include nameplate capacities that are readily identifiable.

We are also including a revision to the definition so that the fossil fuel combustion thresholds of 10 percent over 3 consecutive years and 15 percent in one year are evaluated after the applicable compliance date of the final rule on a rolling basis. Commenters correctly noted that some existing coal- and oil-fired EGUs will convert their units to alternative fuels (*e.g.*, natural gas or biomass) and if the definition were finalized as proposed such units could be improperly subjected to the final standards.

The new definition is set out in 40 CFR 63.10042.

For clarity, we are also removing the definition of "[u]nit designed to burn liquid oil fuel subcategory," revising the definition of "[u]nit designed to burn solid oil fuel subcategory," adding definitions for the continental and non-continental liquid oil-fired EGU subcategories, and adding a definition of a limited-use liquid oil-fired EGU as set out in 40 CFR 63.10042.

In the proposed rule, we stated that we believed EGUs may at times not meet the definition of an EGU subject to this subpart. For example, we explained that there may be some cogeneration units that are determined to be covered under the Boiler NESHAP. Such unit(s) may make a decision to increase the proportion of production output being supplied to the electric utility grid, thus causing the unit(s) to meet the EGU cogeneration criteria (*i.e.*, greater than one-third of its potential output capacity and greater than 25 MW). In the preamble to the proposed rule, we indicated that a unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the EGU NESHAP for the 6-month period after the unit meets the EGU definition.[310] 76 FR 25026. Assuming the EGU did not meet the definition of an EGU following that initial occurrence, at the end of the 6-month period it would revert back to being subject to the Boiler NESHAP, or other applicable standard. We solicited comment on the extent to which situations like this might occur, how the EPA should address situations where units change applicability, and whether we should include provisions similar to those included in the final CISWI (40 CFR 60.2145) to address such situations. *Id.*

Several commenters asked the Agency to include provisions in the final rule that would address situations like the ones described in the preamble to the proposed rule. Because applicability to the final rule is based in part on the statutory definition of an EGU is CAA section 112(a)(8), similar to the situation with units combusting solid waste under CAA section 129(g)(1) (*e.g.*, CISWI Rule), we are adopting provisions in the final rule that are based on the fuel switching provisions of the final CISWI Rule (*See* Final CISWI Rule, 40 CFR 60.2145). For example, a cogeneration unit that did not historically provide more than one third of its potential electrical output capacity to a power distribution system could change its output and provide more than 25 megawatts electrical output to any power distribution system for sale. Such units would be subject to MATS. If the cogeneration unit later reduced its output such that it no longer met the definition of an EGU, that source would nevertheless remain subject to MATS for at least 6 months from the date that the unit first qualified as an EGU.

In addition, we are finalizing a provision whereby you may opt to remain subject to the provisions of this final rule, unless you combust solid waste, in which case you are a solid waste incineration unit subject to standards under CAA section 129 (*e.g.*, 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units), or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units)). We believe the provision to opt to remain subject to this final rule will ameliorate conditions where EGUs may potentially move between NESHAP on a relatively frequent basis. Notwithstanding the provisions of this final rule, an EGU that starts combusting solid waste is subject to standards under CAA section 129, and the unit remains subject to those standards until the unit no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

[310] Although we clearly stated the intent to require sources to comply for 6 months after meeting the definition of an EGU, we inadvertently failed to include the provision in the proposed rule.

The changes to the definitions described above provide clarity to sources, permitting agencies, and the public about the applicability of the rule and help ensure that sources are appropriately covered by the regulation.

B. Subcategories

In this final rule, the EPA is adding subcategories for limited-use oil-fired units and non-continental oil-fired units and revising the definitions for the coal-fired EGU subcategories.

The proposed rule subcategorized EGUs burning coal into two subcategories: EGUs designed for coal ≥8,300 Btu/lb and EGUs designed for virgin coal <8,300 Btu/lb (low rank virgin coal). We received a number of comments indicating that the definition of the low rank virgin coal subcategory was technically deficient.

Under CAA section 112(d)(1), the Administrator has the discretion to "* * * distinguish among classes, types, and sizes of sources within a category or subcategory in establishing * * *" standards. The EPA maintains that, normally, any basis for subcategorization (*i.e.*, class, type, or size) must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. *See* 76 FR 25036–25037. The EPA believes it is not reasonable to exercise our discretion without such a difference because if sources can achieve the same level of emissions reductions notwithstanding a difference in class, type, or size, the purposes of CAA section 112 are better served by requiring a similar level of control for all such units in the category or subcategory. *See Lignite Energy Council* v. *EPA*, 198 F. 3d 930, 933 (D.C. Cir. 1999) ("EPA is not required by law to subcategorize—section 111[b][2] merely states that 'the Administrator *may* distinguish among classes, types, and sizes within categories of new sources'" (emphasis original)); *see* also CAA section 112(d)(1) (containing almost identical language to CAA section 111, CAA section 112(d)(1) provides that "the Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing [ ] standards * * *"). Even if we determine that emissions characteristics are different for units that differ in class, type, or size, the Agency may still decline to subcategorize if there are compelling policy justifications that suggest subcategorization is not appropriate. *Id.*

When developing the proposed rule, we examined the EGUs in the top performing 12 percent of sources for Hg emissions. We determined that:

There were no EGUs designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units. The boiler of a coal-fired EGU designed to burn coal with that heat value is bigger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories. For all other HAP from these two subcategories of coal-fired units, the data did not show any difference in the level of the HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for the other HAP. 76 FR 25036–67.

Based on this determination, we proposed to establish two subcategories with separate Hg limits. Comments on the proposed rule indicate that we correctly identified the EGUs that should be included in each subcategory, but the comments also demonstrated that we made certain incorrect conclusions that require us to revise the definitions of our coal-fired EGU subcategories. The revised definitions ensure that the EGUs we identified at proposal as having different Hg emissions remain in one subcategory.

As stated above, we believed at proposal that the boiler size was the cause of the different Hg emissions characteristics that led us to propose subcategorization, but many commenters indicated that it was not the boiler size but the fact that the EGUs burned a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) (low rank virgin coal) that causes the disparity in Hg emissions. Several commenters indicated that their EGUs were designed to burn and burned low rank virgin coal but the units did not meet the height-to-depth ratio that EPA proposed. For example, the height-to-depth ratio of certain EGUs in this subcategory is in fact 3.5, not 3.82. Further, there are other EGUs in this subcategory that are circulating fluidized bed (CFB) combustion units which do not meet the height-to-depth ratio parameters in the proposed rule, nor are they anything like the pulverized coal (PC) EGUs we initially identified as having the 3.82 height-to-depth ratio.

In addition to the comments concerning EGUs firing this coal, we received comments from at least two commenters indicating that the EPA should clarify in which subcategory a unit belongs when it does not burn low rank virgin coal but is designed to combust low rank virgin coal and has a height-to-depth ratio of greater than 3.82. Commenters also indicated that CFB units that are burning coal-refuse [311] or other nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or greater are "designed to burn" any type of coal. Owners of CFB units that are not firing low rank virgin coal asked which subcategory they belong to based on their ability to burn any type of coal (including low rank virgin coal) without modification. These commenters also indicated that some coal refuse that is combusted has a heating value less than 8,300 Btu/lb but is not "virgin coal." It was unclear to which subcategory they belonged since the proposed rule did not in fact require the unit to burn any specific coal, instead only requiring the unit be "designed" to burn lower Btu coal.

Based on the comments received, we reevaluated the subcategory definitions because we were concerned that the definitions we proposed would improperly categorize a number of the EGUs in both subcategories. We concluded that we should not maintain the proposed definition for "[u]nits designed for coal <8,300 Btu/lb" and exclude the CFB units and PC EGUs with a height-to-depth ratio less than 3.82 that combusted low rank virgin coal.

We were equally concerned that the subcategory definitions not be revised in a manner that would move EGUs that we believed the data show could comply with a more stringent standard into a subcategory with a less stringent standard because, aside from the type of EGUs we identified, all other classes, types, and sizes of EGUs were represented among the top performing 12 percent for Hg in the ≥8,300 Btu/lb subcategory. We were particularly concerned about the CFB units because other CFB units are well represented among the best performing EGUs for Hg in the ≥8,300 Btu/lb subcategory, but the CFB units burning low rank virgin coal are not achieving the same levels of Hg emissions control. Including the best performing CFB units from the other subcategory in the low rank virgin coal subcategory would likely lead to a Hg standard as stringent as the standard for

[311] It is our understanding that no unit combusts coal-refuse from nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb).

EGUs in the ≥8,300 Btu/lb subcategory because the CFB units from the other subcategory would be used to establish the floor. We believe that result would be inconsistent with the intent of the proposed rule. We were also concerned about the information that some EGUs that fired low rank virgin coal had a height-to-depth ratio of 3.5, not 3.82, and that some EGUs that fired other ranks of coal had a height-to-depth ratio greater than 3.82. For these reasons, we did not revise the definition to include CFB units and PC EGUs with a height-to-depth ratio greater than 3.5.

After fully considering the available information, including the comments received, we have concluded that it is appropriate to continue to base the subcategory definitions, at least in part, on whether the EGUs were designed to burn and, in fact, did burn low rank-virgin coal, but that it is not appropriate to continue to use the height-to-depth ratio criteria because that approach would potentially exclude EGUs we identified as having different Hg emission characteristics and include EGUs that did not have different emissions characteristics. We recognize that some commenters have taken the position that it is unlawful to subcategorize based on factors such as fuel type but nothing in the statute prohibits such an approach and the case law supports this approach to the extent courts have considered subcategorization based on such factors. *See Sierra Club* v. *Costle,* 657 F. 2d 298, 318–19 (D.C. Cir. 1981) (differing pollutant content of input material can justify a different standard based on subcategorization authority to "distinguish among classes, types and sizes within categories of new sources"). Furthermore, we believe had Congress intended to prohibit the EPA from subcategorizing based on an EGU being designed to use and using a certain material input (*e.g.,* fuel) it would have clearly stated such intent in the CAA. However, we believe the Agency could decline to exercise its discretion to subcategorize even if the potential result would be the prohibition of the use of some materials if the circumstances warranted. We note that even if we did not subcategorize on the final basis selected, the Hg emissions standard of 1.2E0 lb/Tbtu for the "unit designed for coal ≥8,300 Btu/lb" would remain the same.

We considered basing the subcategory solely on an EGU being designed to burn and burning low rank virgin coal. We decided not to do so because we were concerned that such a definition would allow sources to potentially meet the definition by combusting very small amounts of low rank virgin coal. For example, an EGU on the east coast (or any other region) that was not designed to burn and did not routinely burn low rank virgin coal could import one truck full of low rank virgin coal and burn a very small quantity of it periodically to meet the subcategory definition. To avoid creating this potential loophole, we considered other characteristics that would distinguish EGUs combusting low rank virgin coal.

We determined that these EGUs are universally constructed "at or near" a mine containing low rank virgin coal because it is not cost-effective to transport large quantities of such fuel long distances. Furthermore, we believe that this subcategory of EGUs are almost always built at a mine and limited transportation of the coal is only required as the mine face moves over the course of time. Many such EGUs construct dedicated rail lines, private roads, or conveyor systems to transport the coal to the EGU as the mine face moves. We obtained information from data acquired to develop the CSAPR indicating that the longest distance any EGU firing low rank virgin coal transports that coal is 40 miles. We believe that this distance is near the outer limits for the transport of such coal, but, even for those EGUs, the EGUs were constructed closer to a now idle mine or closer to the working face of a mine that has now expanded away from the EGU site. For these reasons, we are including a requirement that the unit be constructed and operated at or near a mine containing the low rank virgin coal it burns.

We are revising the coal-fired EGU subcategory definitions as set out in 40 CFR 63.10042.

We believe the revised subcategory definitions are reasonable for all the reasons set forth above. The revised definitions maintain the EGUs we identified as having different Hg emissions characteristics in one subcategory and the definitions prevent other EGUs that are not firing low rank virgin coal from being required to comply only with the less stringent Hg emission standard.

As discussed in response to comments, we do not believe that additional subcategorization of other coal-fired EGUs is reasonable or appropriate. All other coal-fired EGUs that are not designed to burn and are burning low rank virgin coal are represented among the best performing sources for Hg, such that no argument exists to support that the Hg emissions from those EGUs are different. In any case, even if emissions are somewhat different as some commenters suggest, we would decline to exercise our discretion because the data demonstrate that the best performing EGUs designed to burn and burning all other ranks of coal are able to achieve the MACT level of control using currently available controls and other HAP emission reduction mechanisms (*e.g.,* coal washing) for the ≥8,300 Btu/lb subcategory.

A second issue related to subcategorization concerns non-continental liquid oil-fired EGUs. At proposal, the EPA did not have sufficient emissions data from non-continental liquid oil-fired EGUs upon which to base a subcategory and took comment on the issue. The data have since been provided in response to the ICR and we received comments suggesting that a non-continental subcategory is appropriate based on the location of such units, the limited availability of alternative fuel sources, and the fact that the emissions characteristics of such units are distinct from continental liquid oil-fired EGUs. The EPA has evaluated the data and comments and we agree that a subcategory is warranted based for the reasons suggested by the commenters. Therefore, the Agency is finalizing the liquid oil-fired EGU subcategories of "continental" and "non-continental."

Lastly, the EPA did not have sufficient information on limited-use liquid oil-fired EGUs upon which to base a subcategory at proposal because some sources required to test under the ICR did not submit the data until after proposal. We took comment on whether a limited-use subcategory was warranted. Commenters indicated that their units were a different class and type of units because many of them were only called to service to address reliability issues associated with, for example, natural gas curtailments. The commenters further indicated that their units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shutdown periods (*e.g.,* they are often only required to run for a couple of hours). These factors would lead to differences in the emissions characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited times that these limited use oil-fired units operate. Based on comments received and our own analysis, we are finalizing a subcategory for limited-use liquid oil-fired EGUs as discussed further elsewhere in this preamble.

C. Emission Limits

The proposed rule included numerical emission limits for PM, Hg, HCl, HF, SO_2, total HAP metals, and individual HAP metals, depending on the subcategory and specific situation. These proposed limits resulted from calculations of MACT floors using information and data available to the Agency prior to proposal, as required by CAA section 112. Based on information and data received during the comment period, we have made data and calculation corrections where necessary and then re-ranked the best performing units in the MACT floor pools. Based on the new ranking, a limited number of the emission limits in the final rule have changed from those proposed.

In addition to adjustments to the emission limits themselves, we are finalizing several other changes to the emission standards that will simplify and improve compliance for sources without compromising the toxics reductions achieved. One key change, as discussed elsewhere in this notice, is that we have changed the surrogate for non-mercury metallic HAP from total particulate matter (PM) to filterable PM for coal-fired and solid oil-derived EGUs. This change is based on information provided in comments and our own conclusion that measurement of filterable PM provided assurance of equivalent HAP emissions control. Most of the non-mercury metal HAP, for which PM is a surrogate, are filterable PM and the one that is not (Se) is well controlled by the limit on acid gases. Using filterable PM as the surrogate will allow us to use continuous PM monitoring systems, which measure filterable (but not total) PM, thereby providing a more continuous measure of compliance.

For liquid oil-fired EGUs, based on comments received and corrections made to the data submitted, we have added a filterable PM limit in the final rule as an alternative equivalent standard for the total metal-HAP limit in the proposed rule. In addition, as discussed elsewhere in this notice, we have added measurement of the moisture content of the oil (with a 1 percent limit) as an alternate compliance assurance measure for liquid oil-fired EGUs for determining compliance with the HCl and HF limits. Direct measurement of HCl and HF remains a compliance demonstration method in the final rule. Finally, as discussed in section VI.D of this notice, the final work practice standard consisting of burner tune-ups, much like those required for organic HAP control, for those limited-use liquid oil-fired EGUs whose annual capacity factor is less than 8 percent.

D. Work Practice Standards for Organic HAP Emissions

As noted earlier in section V.D., the final rule includes a work practice standard for organic HAP, including dioxins and furans, applicable to all EGUs. As noted in section V.D. above, the majority of emissions of these pollutants are below the detection levels of EPA test methods and, therefore, are impractical to measure. The work practice standard, described below, is a practical approach to ensuring that equipment is maintained and run so as to minimize emissions of dioxins and furans, and we expect it to be more effective than establishing a numeric standard that cannot reliably be measured or monitored. The work practice also applies to the limited-use liquid oil-fired subcategory included in the final rule.

The work practice involves maintaining and inspecting the burners and associated combustion controls (as applicable), tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after the burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. In Table 3 of the final regulation, we have clarified that this refers to performance tune-ups, not tests, and have addressed the frequency requirement as discussed in response to comments about the appropriateness of the 18-month frequency. The provisions of 40 CFR 63.10006(h)(i) refer to 40 CFR 63.10021(e) for the specific steps required to be part of the periodic tune-up. We have also adjusted the language in the final rule to recognize the value of automated boiler optimization tools such as neural network systems.

Under the final rule, the tune-up must be conducted at each planned major outage and in no event less frequently than every 36 calendar months, with an exception that if the unit employs a neural-network system for combustion optimization during hours of normal unit operation, the required frequency is a minimum of once every 4 years (48 calendar months). Initial compliance with the work practice standard of maintaining burners must occur within 180 days of the compliance date of the rule. The initial compliance demonstration for the work practice standard of conducting a tune-up may occur prior to the compliance date of the rule, but must occur no later than 42 months (36 months plus 180 days) from the compliance date of the rule or, in the case of units employing neural network combustion controls, 54 months (48 months plus 180 days). If the tune-up occurs prior to the compliance date of the rule, you must maintain adequate records to show that the tune-up met the requirements of this standard.

We have made a number of specific changes to address what to do for repairs that may require longer term corrective actions, additional methods for evaluating combustion effectiveness, and clarification on procedures for recording CO and NO_X information. There were specific comments that opposed the reference to manufacturer specifications, if available. We retained this language in the final rule, but note that these specifications apply only to the extent applicable. Specifically, if manufacturer specifications only address equipment or conditions that are no longer present given current boiler operations, then those specifications are not applicable and other combustion engineering best practice procedures for that burner type would apply. We have also clarified that portable emission monitoring equipment may be used to collect the required emissions optimization data regarding pre- and post-tune-up CO and NO_X emission levels.

E. Requirements During Startup, Shutdown, and Malfunction

We proposed numerical emission standards that would apply at all times, including during periods of startup, shutdown, and malfunction. Although at proposal we stated that we were not setting a different standard for startup and shutdown, we did propose different standards for startup and shutdown by our inclusion of the default values described below, which applied only during startup and shutdown. Specifically, we stated:

> To appropriately determine emissions during startup and shutdown and account for those emissions in assessing compliance with the proposed emission standards, we propose use of a default diluent value of 10.0 percent O_2 or the corresponding fuel specific CO_2 concentration for calculating emissions in units of lb/MMBtu or lb/TBtu during startup or shutdown periods. For calculating emissions in units of lb/MWh or lb/GWh, we propose source owners use an electrical production rate of 5 percent of rated capacity during periods of startup or shutdown. We recognize that there are other approaches for determining emissions during periods of startup and shutdown, and we request comment on those approaches. We further solicit comment on the proposed approach described above and whether the values we are proposing are appropriate.

We proposed application of the respective emission limits during periods of startup and shutdown and use of default values to calculate the emission limits. The standards that apply at all times other than startup and shutdown are production-based limits, which is why we proposed the default values. The default values were meant to account for the fact that during startup and shutdown events, production (in this case the generation of electricity) is by definition nonexistent. Thus, in effect, we proposed a separate standard to apply during startup and shutdown.

We received a variety of comments on the proposed standards that would apply during startup and shutdown. Many commenters pointed to the lack of data in the record concerning emissions that occur during periods of startup and shutdown. They further asserted that emissions during these periods can be highly variable in light of the sequence of events that occurs during the startup and shutdown of an EGU. Although a number of commenters supported the use of the diluent factor approach, including the default 5 percent of rated capacity, during startup/shutdown periods, other commenters questioned the feasibility of collecting additional data during such periods and had concerns regarding the reliability of measurements obtained from EGUs during such periods.

In response to the Agency's ICR to the utility industry, seven owners or operators indicated that they provided startup and shutdown data for their EGUs. These data were submitted in response to the requirement in the ICR to provide all available data from the 5 years prior to the date the ICR was issued. Of these data, there were almost no HAP data for startup and shutdown periods and almost all of the data failed to meet our data quality requirements.[312] Thus, we do not have sufficient data on emissions that occur during startup and shutdown on which to set emission standards. We are therefore establishing work practice standards rather than numeric emissions standards for periods of startup and shutdown in the final rule. Before we describe those work practices, we first address what constitutes startup and shutdown.

Several commenters had an expansive view of what constitutes startup and shutdown. We disagree with these commenters that asserted that periods of "load swings" should be considered "startup" or "shutdown," as they are generally routine, normal operations with production (*i.e.*, generation of electricity) taking place. We maintain that the standards as promulgated account for any variability in emissions that may occur during these periods over a 30-day averaging period, and commenters have provided no data that cause us to doubt that determination. We have included definitions of startup and shutdown in the final rule that are consistent with the definitions in the proposed rule. At proposal, we defined startup as the setting in operation of an affected source or portion of an affected source for any purpose, and shutdown as the cessation of operation of an affected source or portion of an affected source for any purpose.

Commenters sought more clarity regarding the meaning of these terms as applied to EGUs, so we are revising the definitions in the final rule as set out in 40 CFR 63.10042.

These interpretations are tailored for EGUs and are consistent with the definitions of "startup" and "shutdown" contained in the 40 CFR part 63, subpart A General Provisions. We believe these revised definitions address the comments and are rational based on the fact that EGUs function to provide electricity primarily for sale to the grid but also at times for use on-site; therefore, EGUs should be considered to be operating normally at all times electricity is generated. We further believe these revised definitions address what some commenters describe as "warm" and "hot" startups as long as the EGU is shutdown (*i.e.*, no fuel fired and no electricity generation) prior to the "warm" or "hot" startup period.

As for the work practices, in this final rule, the EPA is requiring sources to operate using either natural gas or distillate oil for ignition during startup. The EPA also is requiring sources to vent emissions to the main stack(s) and operate all control devices necessary to meet the normal operating standards under this final rule (with the exception of dry scrubbers and SCRs) when coal, solid oil-derived fuel, or residual oil is fired in the boiler during startup or shutdown. It is the responsibility of the operators of EGUs to start their dry scrubber and SCR systems appropriately to comply with relevant standards applicable during normal operation.

The EPA carefully considered fuels and potential operational constraints of air pollution control devices (APCDs) when designing its work practices for periods of startup and shutdown. The EPA notes that there is no technical barrier to burning natural gas or distillate oil for longer portions of startup or shutdown periods, if needed, at a boiler, and the HAP emission reduction benefits warrant additional utilization of such fuels until the temperature and stack emissions pressure is sufficient to engage the APCDs. The EPA is aware that SCR systems with ammonia injection need to be operated within a prescribed and relatively narrow temperature window to provide NO_X reductions. Further, the EPA is aware that dry scrubbers also need to be operated close to flue gas saturation temperature. Because these devices have specific temperature requirements for proper operation, the EPA notes in its work practices that it is the responsibility of the operators of EGUs to start their SCR and dry scrubber systems appropriately to comply with relevant standards applicable during normal operation.

Some commenters have asserted that firing of fuel oil during periods of startup and shutdown constrains operation of PM controls (ESPs and baghouses) because under cooler conditions, acids and tars can condense on surfaces in these controls. The commenters assert that such condensation can cause detrimental impacts on hardware and operation of these controls, and could cause safety concerns. The EPA understands that concerns with acidic and tarry deposits are related to firing of heavy (residual) oil and not distillate oil. Accordingly, with residual fuel oil firing, site-specific flue gas temperature and oxygen (O_2) concentration thresholds may be applicable to minimize condensation of acids and tars and thereby minimize any potential for detrimental impacts on hardware and any safety concerns.

[312] In response to the ICR, we also received SO_2 CEMS data and the Agency had additional SO_2 CEMS data available through the CAMD ARP database. We are not able to identify specific periods of start-up and shutdown in either the ICR CEMS data or the CAMD ARP data, and the ICR respondents do not indicate that the ICR data includes periods of startup and shutdown. We set the emission limits for SO_2 and HCl using the data provided to the EPA from the 2010 ICR, not the CAMD data, since those data were taken concurrently under the same specified operating conditions using the same fuel. We used the SO_2 CEMS data that was submitted in response to the ICR by converting it to single point data to correlate to the data from units that did not provide CEMS data from the relevant testing period. The emissions limits for the NESHAP incorporated variability by applying the 99 percent UPL to the average emissions developed from the stack test data and SO_2 CEMS data that was converted to stack test data. Thus, we did not have data on which to establish an SO_2 standard during periods of startup and shutdown and the numeric standards do not apply to those periods in the final rule. In contrast, the NSPS for SO_2 is applicable during periods of startup and shutdown since the long term CAMD ARP CEMS data were used to determine the average performance of the best demonstrated technology. Those long term data were assumed to incorporate process variability including that associated with fuel and process/operational changes and periods of startup and shutdown.

However, the EPA notes that its work practice requirements provide flexibility to the operator to take appropriate site-specific remedial measures, if needed. The EPA further notes that boilers have several options to prevent detrimental impacts by: (1) Using startup fuels, natural gas or distillate oil, until appropriate flue gas conditions have been reached and then fire residual oil; (2) pre-coating the PM control surfaces [313] with an alkaline powder (*e.g.*, limestone); (3) installing chemically resistant bags [314] in baghouses if applicable; and (4) using low-sulfur oils. The EPA also notes that currently the industry has many operational residual oil-fired boilers that are started up with either natural gas or distillate fuel oil. At these boilers, the transition from the startup fuel, distillate oil or natural gas, to residual oil is already being practiced without unacceptable impacts on APCDs including PM controls, which are operated to meet applicable opacity limits. Based on this experience and the options described above, those boilers where residual oil is used for either a part of the startup period, or as the main fuel, will also be able to operate their PM controls to meet the work practice requirements of the rule. Note that coal firing is done at high enough temperatures that concerns with condensation are not relevant. None of the commenters have specifically commented on this aspect of coal firing.

The EPA is not aware of any operational constraints applicable to operation of wet scrubbers during startup that could cause detrimental impacts on wet scrubber hardware and safety concerns and none of the commenters have commented on this aspect of wet scrubber operation.

Finally, the EPA notes that dry sorbent injection (DSI) can be applied across a very broad temperature range and will be engaged when residual oil or coal is fired in a boiler to comply with HCl requirements. Again, no comments have been received on this aspect of DSI operation.

This final rule requires work practice standards for emissions during startup and shutdown, and the rule requires sources to measure and report their emissions at all times, including periods of startup and shutdown, when continuous monitoring is used to demonstrate compliance. Data collected under this final rule will provide the EPA with information to more fully analyze this issue and address it during the 8-year review established under CAA section 112.

We now address malfunctions. In contrast to the exclusion of startup and shutdown period emissions from 30-boiler operating day rolling average emissions, the final rule requires inclusion of emissions during periods of source or APCD malfunction. We have concluded that when combined with the availability of an affirmative defense as described below, this is an appropriate and practical approach.

As mentioned earlier, periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 63.2). The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. Under CAA section 112, emissions standards for new sources must be no less stringent than the level "achieved" by the best controlled similar source and for existing sources generally must be no less stringent than the average emission limitation "achieved" by the best performing 12 percent of sources in the category. There is nothing in CAA section 112 that directs the Agency to consider malfunctions in determining the level "achieved" by the best performing or best controlled sources when setting emission standards. Moreover, while the EPA accounts for variability in setting emissions standards consistent with the CAA section 112 case law, nothing in that case law requires the Agency to consider malfunctions as part of that analysis. Clean Air Act section 112 uses the concept of "best controlled" and "best performing" unit in defining the level of stringency that CAA section 112 performance standards must meet. Applying the concept of "best controlled" or "best performing" to a unit that is malfunctioning presents significant difficulties, as malfunctions are sudden and unexpected events.

Further, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not "reasonably" foreseeable. *See, e.g., Sierra Club* v. *EPA*, 167 F. 3d 658, 662 (D.C. Cir. 1999) (The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to "invest the resources to conduct the perfect study."). *See also, Weyerhaeuser* v. *Costle*, 590 F.2d 1011, 1058 (D.C. Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation."). In addition, the goal of a best controlled or best performing source is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with CAA section 112, and we believe it is a reasonable interpretation of the statute. This approach to malfunctions has been used consistently in CAA section 112 and CAA section 129 rulemaking actions since the D.C. Circuit's decision in *Sierra Club* v. *EPA*, 551 F.3d 1019 (D.C. Cir. 2008) vacated the SSM exemption contained in CFR 63.6(f)(1) and 40 CFR 63.6(h)(1). (*See, e.g.*, National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants, 75 FR 54970 (September 9, 2010); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units; Final Rule, 76 FR 15372 (March 21, 2011).

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses

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[313] Coal Power, May 1, 2007: *http://www.coalpowermag.com/plant_design/Coal-Plant-O-and-M-River-Locks-and-Barges-Are-an-Aging-Workforce-Too 36.html.*

[314] Neundorfer: Lesson #r, p.4–7, Table 4–1: *http://www.neundorfer.com/FileUploads/CMSFiles/Fabric%20Filter%2OMaterial [0].pdf.*

to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). The EPA is therefore adding to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. *See* 40 CFR 63.10042 (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also have added other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 63.10001. (*See* 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (*i.e.,* sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation). For example, to assert the affirmative defense successfully, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *" The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 63.10001 and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *" In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 (*see* also 40 CFR 22.27).

The EPA is including an affirmative defense in the final rule as we have in other recent MACT rules so as to balance the tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that "limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis." 42 U.S.C. 7602(k) (defining "emission limitation and emission standard"). *See* generally *Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (D.C. Cir. 2008). Thus, the EPA is required to ensure that section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief. While "continuous" limitations, on the one hand, are required, there is also case law indicating that in some situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit acknowledged that in setting standards under CAA section 111 "variant provisions" such as provisions allowing for upsets during startup, shutdown and equipment malfunction "appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force." *See* also, *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973). Though intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments calls into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating "upsets beyond the control of the permit holder." *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). But *see, Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to ensure both that its emission limitations are "continuous" as required by 42 U.S.C. 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

F. Testing and Initial Compliance

We have carefully evaluated the wide-ranging comments on testing, continuous monitoring, and other provisions regarding initial compliance demonstrations, and we have made adjustments intended to help streamline implementation while still ensuring adequate demonstration of compliance with the emission limits and other standards established under this final rule. The significant changes include:

1. No Fuel Analysis Requirements

Apart from an alternative that allows you to analyze fuel moisture for liquid oil-fired EGUs rather than measuring HCl and HF, the final rule does not include any of the fuel analysis requirements that were in the proposed rule, either as part of initial compliance demonstrations or ongoing compliance demonstrations. In reviewing the results of the fuel analyses and the expected range of results that would be received from laboratories conducting the proposed analyses, we determined that too many results would be returned as "below detection level" and, thus, provide little information to assist with rule implementation and compliance oversight. Given the costs and efforts involved, we determined that the proposed fuel analysis requirements would not be an effective compliance monitoring tool for this final rule.

2. Clarification of Testing

We have clarified that where options for emission limits apply (such as filterable PM versus non-mercury HAP metals, or SO_2 versus HCl), you need only perform stack testing to demonstrate compliance with the selected emission limit. For example, if you elect to meet the individual non-

mercury HAP metals standards, you must conduct the Method 29 test for the metals, and you do not have to conduct a Method 5 test for PM.

3. Low Emitting EGU Qualification

We have significantly modified the proposed requirements to qualify as a LEE unit for a pollutant other than Hg based on an initial performance test. Under the proposed rule, the operating limit monitoring provided additional assurance of compliance for a source qualified for non-mercury LEE status based on an initial compliance demonstration. Under the final rule, to qualify for LEE status for pollutants other than Hg, a unit must meet the LEE criteria for a series of performance tests over a 3-year period to demonstrate that the unit continues to perform well below the standard for which the source has obtained LEE status.

G. Continuous Compliance

The most significant changes to the testing and monitoring requirements involve the procedures for demonstrating continuous compliance. The proposed rule contained different options involving CEMS, periodic stack tests, fuel analysis, and various PM and control device operating limits. The final rule greatly simplifies the requirements and provides two basic approaches for most situations: use of continuous monitoring (either CEMS or PM continuous parametric monitoring system, CPMS) or periodic quarterly testing. The final rule does not contain the proposed fuel analysis requirements. For periodic testing, the proposed rule required testing every month or every 2 months. For those EGU owners or operators who choose to use emissions testing to demonstrate compliance, the final rule requires quarterly filterable PM or non-mercury metals HAP, whether individual or total metals, testing for coal- and liquid oil-fired units. The rule requires quarterly HCl testing for coal-fired units and quarterly HCl and HF testing, along with site-specific monitoring for liquid oil-fired units to ensure compliance with the HCl and HF standards. The final rule also has a separate compliance demonstration for those liquid oil-fired EGUs that have an annual capacity factor of less than 8 percent (emission limits do not apply, just the tune-up work practice standard). For those EGU owners or operators who choose to use emissions testing to demonstrate compliance, the final rule requires quarterly filterable PM or non-mercury metals HAP, whether individual or total metals, testing for coal- and liquid oil-fired units; quarterly HCl testing for coal-fired units and quarterly HCl and HF testing, along with site-specific parameter monitoring for liquid oil-fired units to ensure compliance with the HCl and HF standards.

The continuous monitoring options remain generally intact from the proposed rule, with relatively minor clarifications concerning calculation of 30-boiler operating day averages and QA requirements.

The final rule eliminates all operating limits for PM except for the use of a PM CPMS. For the PM CPMS, the final rule clarifies procedures for setting this operating limit and how it is distinct from the PM emission limit. The PM CPMS will not be correlated as a PM CEMS under PS 11 and will produce data in terms of a signal you define. That signal could be milliamps, stack concentration, or other output signal instead of PM emissions in units of the standard. The operating limit will be set using the highest hourly average obtained from the PM CPMS during the performance test. Compliance with the limit is based on a 30-boiler operating day rolling average basis. However, the final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach. The EPA believes that some sources may be interested in adopting this direct approach, and so has included that option in the final rule. If this approach is selected, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11 and Procedure 2. To use this option, the source must elect to meet the filterable PM standard, and not one of the HAP metals standards.

Apart from the operating limit for site-specific monitoring associated with liquid oil-fired EGUs, we removed the other operating limits for control devices based on a review of the comments, after considering other programs in place to ensure proper operations of controls at EGUs. Those other programs include compliance assurance monitoring under part 64, part 70, and New Source Review permit conditions, and other SIP and NSPS requirements for operating and maintaining equipment in accordance with good air pollution control practices. Those requirements, in combination with the CEMS, PM CPMS, and frequent periodic testing provisions under the final rule, will enhance the monitoring of continuous compliance with the requirements of this rule.

Because the EPA is concerned that there will be little or no monitoring in these underlying applicable requirements for acid gases at liquid oil-fired EGUs, the final rule requires a site-specific monitoring plan for those units in this subcategory that demonstrate compliance with the HCl and HF standards through quarterly performance tests. With the exception for limited-use liquid oil-fired EGUs and other monitoring options available (such as fuel moisture monitoring or HCl/HF CEMS), the EPA believes this provision will apply to few units. The owner or operator will submit the site-specific plan to identify appropriate parameters that ensure that the operations of the unit critical to meeting the HCl/HF emission limits remain consistent with conditions during performance testing. This will be approved similarly to an alternative monitoring request. The plan should include the parameters, monitoring approach, QA/QC elements, and data reduction (including averaging period) elements. Like the PM CPMS operating limit, the operating limit for acid gas control devices on liquid oil-fired EGUs will be set using the highest hourly average obtained during the HCl and HF performance tests. Compliance with the limit is based on a 30-boiler operating day rolling average basis.

Finally, we have changed the continuous compliance requirements for the performance tune-up work practice standard since the proposal. Our intent was that this work practice standard could be performed in conjunction with routine maintenance operations at a facility and be a logical extension of routine best practices for boiler inspection and optimization. Based on the comments received, we have reduced the required frequency for this inspection to every 3 years and provided incentives for neural network combustion management and optimization practices by providing a longer interval of 4 years between inspections when such systems are in use at a given EGU.

H. Emissions Averaging

We are finalizing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for existing EGUs that are located at the same facility that are within a single subcategory and that rely on emissions testing as the compliance demonstration method. In response to our request for comments on the suitability of emissions averaging and need for a discount factor, we received a range of suggestions, including requests for clarification regarding eligibility, points for and against the need for a discount factor, and suggestions to ease implementation.

As we noted at proposal, part of the EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced is to include emissions averaging. Emissions averaging can provide sources the flexibility to comply in the least costly manner while still maintaining a regulation that is workable and enforceable. Emissions averaging would not be applicable to new affected sources and could only be used between EGUs in the same subcategory at a particular facility. Also, owners or operators of existing sources subject to the EGU NSPS (40 CFR part 60, subparts D and Da) would be required to continue to meet the PM emission standard of that NSPS regardless of whether or not they are using emissions averaging (*i.e.*, an EGU subject to 40 CFR part 60, subpart D or Da must meet its applicable NSPS filterable PM emission limit even if it is included in a 40 CFR part 63, subpart UUUUU, emissions averaging group for filterable PM).

Emissions averaging allows owners and operators of a facility that includes existing EGUs within a subcategory to demonstrate that the source complies with the proposed emission limits by averaging the emissions from an individual affected EGU that is emitting above the proposed emission limits with other affected EGUs at the same facility that are emitting below the proposed emission limits and that are within the same subcategory. Although some commenters note that the MACT limits are low, based on the data available to the Agency, we believe that dozens of existing EGUs are achieving all of the limits and, thus, emissions averaging is a possible approach.

The final rule includes an emissions averaging compliance alternative because emissions averaging [315] represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels. We have concluded that averaging in the proposed rule could be implemented and that it would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators. We also recognize that we must ensure that any emissions averaging option can be implemented and enforced, will be clear to sources, and most importantly, will be no less stringent than unit-by-unit implementation of the MACT floor limits.

In the final rule, the EPA is providing that sources may average emissions from existing EGUs at the same facility and within the same subcategory. Further, for Hg emissions only from existing EGUs within the same subcategory, such EGUs in an emissions averaging plan may use an alternate compliance approach consisting of a 90-boiler operating day rolling average emission limit of 1.0 lb/TBtu or 1.1E–2 lb/GWh.

In the memo entitled "The Impact of Emission Averaging Time on the Stringency of an Emission Standard" in the docket, we have illustrated why a longer-term average results in a lower limit. In essence, longer-term averages allow particularly high (or low) measurements to be averaged with many more measurements closer to the mean. This results in the highest averages from a longer-term averaging period (*e.g.*, 90 days) being lower than the highest averages in a shorter term averaging period (*e.g.*, 30 days).

We have illustrated this concept by taking Hg CEMS data and calculating rolling 30-day averages and rolling 90-day averages. The 30-day averages have greater variability and, thus, higher peaks and valleys. The 90-day average has less variability; therefore, the same unit is able to meet a tighter 90-day limit.

The EPA is providing this alternate 90-day rolling average compliance approach for Hg only. A 90-day rolling average is appropriate for Hg, and only for Hg, because the health and environmental impacts associated with Hg are related to environmental loading rather than shorter term inhalation or other acute exposure, as is the case with HCl and PM. We believe that this alternative compliance approach will provide at least the same level of environmental protection while allowing companies greater flexibility to use emissions averaging. For example, such an approach would allow for the averaging of an infrequently operated unit that is operating slightly above the standard with a more frequently operated unit that is operating below the standard in the instances when the more frequently operated unit is in a multi-day or multi-week maintenance outage.

The EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging within the same facility across individual existing EGUs subject to the same standards under certain conditions. As mentioned earlier, individual EGUs within an emissions averaging group would be allowed to have emissions greater than, less than, or equivalent with the emissions limit for their subcategory, provided that the average emissions comprised from individual EGU emissions do not exceed the emissions limit for their subcategory. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the same standards in the NESHAP will not be greater under the averaging mechanism than it could be if each individual affected EGU in the subcategory complied separately with the applicable standard. Under this test, the practical outcome of averaging is equivalent to compliance with the MACT floor limits by each discrete EGU, and the statutory requirement that the MACT standard reflect the maximum achievable emissions reductions is, therefore, fully effectuated.

As noted in the proposal preamble, in past rulemakings, the EPA has generally imposed certain limits on the scope and nature of emissions averaging programs. These limits include: (1) No averaging between different types of pollutants; (2) No averaging between sources that are not part of the same affected source; (3) No averaging between individual sources within a single major source if the individual sources are not subject to the same NESHAP; and (4) No averaging between existing sources and new sources.

The final rule fully satisfies each of these criteria. First, emissions averaging would only be permitted between individual existing sources at a single stationary source (*i.e.*, the facility), and would only be permitted between individual sources in the same subcategory in the final EGU NESHAP. Further, emissions averaging would not be permitted between two or more different affected sources. Finally, new affected sources could not use emissions averaging. Accordingly, we have concluded that the averaging of emissions across affected units in the same existing source subcategory is consistent with the CAA. In addition, the final rule requires each facility that intends to utilize emissions averaging to develop an emissions averaging plan, which provides additional assurance that the necessary criteria will be followed. In this emissions averaging plan, the facility must include the identification of: (1) All units in the averaging group; (2) the control technology installed; (3) the process parameter that will be monitored; (4) the specific control technology or pollution

[315] As long as required emission rates are designed to account for factors such as changes in averaging times.

prevention measure to be used; (5) the test plan for the measurement of the HAP being averaged; and (6) the operating parameters to be monitored for each control device. A state, local, or tribal regulatory agency that is delegated authority for this rule could require the emissions averaging plan to be submitted or even approved before emissions averaging could be used. Upon receipt, the regulatory authority would not be able to approve an emissions averaging plan differing from the eligibility criteria contained in the rule.

The final rule excludes new affected sources from the emissions averaging provision. The EPA does not believe the statute authorizes emissions averaging for new affected sources. One reason we allow emissions averaging is to give existing sources flexibility to achieve compliance at diverse points with varying degrees of add-on control already in place in the most cost-effective and technically reasonable fashion.

With the monitoring and compliance provisions that are being finalized, there is additional assurance that the environmental benefit will be realized. Further, the emissions averaging provision would not apply to individual EGUs if the EGU shares a common stack with units in other subcategories, because in that circumstance it is not possible to distinguish the emissions from each individual unit.[316]

The rule allows EGUs that rely on CEMS for compliance demonstrations to be able to participate in emissions averaging and the emissions limits are not subject to a discount. The EPA believes that the data certainty provided by units that use CEMS would be ideal for emissions averaging and the flexibility and cost-effectiveness it offers. Given the homogeneity of fuels within the rules subcategories, along with other emissions averaging criteria, the Agency believes use of a discount factor to be unwarranted for this rule.

The emissions averaging provisions in this final rule are based in part on the emissions averaging provisions in the Hazardous Organic NESHAP (HON). The legal basis and rationale for the HON emissions averaging provisions were provided in the preamble to the final HON.[317] We do not believe that we have the authority to provide for emissions averaging among EGUs in different subcategories or among EGUs not physically located at the same affected facility.

I. Notification, Recordkeeping, and Reporting

Compared to the proposed rule, the reduced continuous compliance requirements in the final rule—primarily reduced testing frequencies and removal of fuel analyses and control device or fuel operating parameter monitoring—considerably reduces the overall burden associated with recordkeeping and reporting. Based on evaluation of the comments received, we have established a provision in the final rule for submission of most CEMS data (including monitoring plan, emissions data, and QA data) through ECMPS, so that the affected industry uses a common reporting tool for submitting CEMS data.

For data other than most CEMS data, the final rule requires electronic reporting of certain data, including performance test reports, PM CPMS data, PM CEMS data, and, if approved as part of an alternative monitoring request, HAP metals CEMS data. Other reports, such as notifications, must be submitted in hard copy format or in accordance with the procedures established by state and local agencies that receive delegation for implementing this rule. In the proposed rule, we took comment on these approaches and stated our anticipation of adopting these approaches. In the final rule, we have extended the ECMPS reporting to most CEMS data to promote harmonization for CEMS data from the industry, while leaving reporting of non-CEMS data in a separate reporting system.

J. Technical/Editorial Corrections

In this final action, we are making a number of technical corrections and clarifications to 40 CFR part 63, subpart UUUUU. These changes clarify procedures for implementing the emission limitations for affected sources. We are also clarifying several definitions to help affected sources determine applicability of this rule. We have modified some proposed regulatory language based on public comments. In addition, in response to comments received (including the May 2010 notice from the Utility Air Regulatory Group (UARG) of calculation errors in the proposed Hg MACT floor limits), we have checked all calculations and made corrections where necessary.

In several places throughout the subpart, including the associated tables, we have corrected the cross-references to other sections and paragraphs of the subpart.

VII. Public Comments and Responses to the Proposed NESHAP

A. MACT Floor Analysis

1. New Data/Technical Corrections to Old Data

Comment: Many commenters identified errors in the emissions database compiled through information provided by industry in response to the 2010 information collection request (ICR) that supported development of this rule. Commenters submitted corrections to the EPA during the public comment period.

Response: The EPA has incorporated technical corrections and new data submitted prior to the end of the comment period. The corrections and new data are described in detail in a memorandum in the docket. The EPA re-ranked the sources in the MACT floor pools to the extent necessary based on the new or corrected data, and we recalculated the MACT floors as necessary based on the re-ranking of sources. The revised MACT floors were established using the same methodology set forth in the proposed rule.

2. Pollutant-by-Pollutant Approach

Comment: Many commenters raised concerns about the way the EPA determined the MACT floors using a pollutant-by-pollutant approach. Commenters contended that such a methodology produced limits that are not achievable in combination, and as such, the limits do not comport with the intent of the statute or the recent court decision (*NRDC* v. *EPA*, 2007). Commenters further added that the CAA directs the EPA to set standards based on the overall performance of "sources" and CAA sections 112(d)(1), (2), and (3) specify that emissions standards be established on the "in practice" performance of a "source" in the category or subcategory. Commenters stated that if Congress had intended for the EPA to establish MACT floor levels considering the achievable emission limits of individual HAP, it could have worded CAA section 112(d)(3) to refer to the best-performing sources "for each pollutant." Many commenters added that the EPA's discretion in setting standards is limited to distinguishing among classes, types, and sizes of sources. Commenters contend that although Congress limited the EPA's authority to parse units and sources with similar design and types, it does not allow the EPA to "distinguish" units and sources by individual pollutant as proposed in this rule (*Sierra Club* v. *EPA*, 551 F.3d 1019, 1028 (D.C. Cir. 2008)). By calculating each MACT floor

[316] The EPA has reviewed monitoring data submitted to the Agency under the Title IV Acid Rain Program. Based on that review, the EPA is unaware of any coal- and oil-fired units that share a common stack.

[317] Hazardous Organic NESHAP (59 FR 19,425; April 22, 1994).

independently of the other pollutants, commenters contend that the combination of HAP limits results in a set of standards that only a hypothetical "best performing" unit could achieve.

Response: We disagree with the commenters who believe MACT floors cannot be set on a pollutant-by pollutant basis. Contrary to the commenters' suggestion, CAA section 112(d)(3) does not mandate a total facility approach. A reasonable interpretation of CAA section 112(d)(3) is that MACT floors may be established on a HAP-by-HAP basis, so that there can be different pools of best performers for each HAP. Indeed, as illustrated below, the total facility approach not only is not compelled by the statutory language but can lead to results so arbitrary that the approach may simply not be legally permissible.

Clean Air Act section 112(d)(3) is not explicit as to whether the MACT floor is to be based on the performance of an entire source or on the performance achieved in controlling particular HAP. Congress specified in CAA section 112(d)(3) the minimum level of emission reduction that could satisfy the requirement to adopt MACT. For new sources, this floor level is to be "the emission control that is achieved in practice by the best controlled similar source." For existing sources, the floor level is to be "the average emission limitation achieved by the best performing 12 percent of the existing sources" for categories and subcategories with 30 or more sources, or "the average emission limitation achieved by the best performing 5 sources" for categories and subcategories with fewer than 30 sources. Commenters point to the statute's reference to the best performing "sources," and claim that Congress would have specifically referred to the best performing sources "for each pollutant" if it intended for the EPA to establish MACT floors separately for each HAP.

The EPA disagrees. The language of the Act does not address whether floor levels can be established HAP-by-HAP or by any other means. The reference to "sources" does not lead to the assumption the commenters make that the best performing sources can only be the best-performing sources for the entire suite of regulated HAP. Instead, the language can be reasonably interpreted as referring to the source as a whole or to performance as to a particular HAP. Similarly, the reference in the new source MACT floor provision to "emission control achieved by the best controlled similar source" can mean emission control as to a particular HAP or emission control achieved by a source as a whole.

Commenters also stressed that CAA section 112(d) requires that floors be based on actual performance from real facilities. The EPA agrees that this language refers to sources' actual operation, but again the language says nothing about whether it is referring to performance as to individual HAP or to single facility's performance for all HAP. Industry commenters also said that Congress could have mandated a HAP-by-HAP result by using the phrase "for each HAP" at appropriate points in CAA section 112(d). The fact that Congress did not do so does not compel any inference that Congress was *sub-silentio* mandating a different result when it left the provision ambiguous on this issue. The argument that MACT floors set HAP-by-HAP are based on the performance of a hypothetical facility, so that the limitations are not based on those achieved in practice, just reiterates the question of whether CAA section 112(d)(3) refers to whole facilities or individual HAP. All of the limitations in the floors in this rule reflect sources' actual performance and were achieved in practice. As to commenters' claims that standards set in this manner cannot be met by any actual sources, we have determined that there are approximately 69 existing coal-fired EGUs that meet all of the final existing source MACT emission limits (out of 252 EGUs that reported data for Hg, PM, and HCl in the 2010 ICR) and at least one EGU that meets all of the final new source MACT emission limits.

Commenters also point to the EPA's subcategorization authority, and claim that because Congress authorized the EPA to distinguish among classes, types, and sizes of units, the EPA cannot distinguish units by individual pollutant, as they allege the EPA did in the proposed rule. However, that statutory language addresses the EPA's authority to subcategorize sources within a source category prior to setting standards, which the EPA has done for certain EGUs. The EPA is not distinguishing within each subcategory based on HAP emitted. Rather, it is establishing emissions standards based on the emissions limits achieved by units in each subcategory. Therefore, the EPA's subcategorization authority is irrelevant to the question of how the EPA establishes MACT floor standards once it has made the decision to distinguish among sources and create subcategories.

The EPA's long-standing interpretation of the Act is that the existing and new source MACT floors are to be established on a HAP-by-HAP basis. One reason for this interpretation is that a whole plant approach could yield least common denominator floors—that is, floors reflecting limited or no control, rather than performance which is the average of what best performers have achieved. *See* 61 FR 173687 (April 19, 1996); 62 FR 48363–64 (September 15, 1997) (same approach adopted under the very similar language of CAA section 129(a)(2)). Such an approach would allow the performance of sources that are outside of the best-performing 12 percent for certain pollutants to be included in the floor calculations for those same pollutants, and it is even conceivable that the worst performing source for a pollutant could be considered a best performer overall, a result Congress could not have intended. Inclusion of units that are outside of the best performing 12 percent for particular pollutants would lead to emission limits that do not meet the requirements of the statute.

For example, if the best performing 12 percent of facilities for HAP metals were also the worst performing units for acid gas HAP and the best performers for acid gas HAP were the worst performers for HAP metals, the floor for acid gases or metals would end up not reflecting best performance. In such a situation, the EPA would have to make a value judgment as to which pollutant reductions were most critical to decide which sources are best controlled.[318] Such value judgments are antithetical to the direction of the statute at the MACT floor-setting stage.

Commenters suggested that a multi-pollutant approach could be implemented by weighting pollutants according to relative toxicity and calculating weighted emissions totals to use as a basis for identifying and ranking best performers. This suggested approach would require the EPA to essentially prioritize the regulated HAP based on relative risk to human health of each pollutant, where risk is a criterion that has no place in the establishment of MACT floors, which are required by statute to be based on technology.

The central purpose of the amended air toxics provisions was to apply strict technology-based emission controls on HAP. *See, e.g.*, H. Rep. No. 952, 101st Cong. 2d sess. 338. An interpretation that the floor level of control must be limited by the performance of devices

[318] See Petitioners Brief in *Medical Waste Institute et al.* v. *EPA*, No. 09–1297 (D.C. Cir.) pointing out, in this context, that "the best performers for some pollutants are the worst performers for others" (p. 34) and "[s]ome of the best performers for certain pollutants are among the worst performers for others."

that only control some of these pollutants effectively guts the standards by including worse performers in the averaging process, whereas the EPA's interpretation promotes the evident Congressional objective of having the floor reflect the average performance of best performing sources. Because Congress has not spoken to the precise question at issue, and the Agency's interpretation effectuates statutory goals and policies in a reasonable manner, its interpretation must be upheld. *See Chevron* v. *NRDC,* 467 U.S. 837 (1984).[319]

The EPA notes, however, that if optimized performance for different HAP is not technologically possible due to mutually inconsistent control technologies (for example, if metals performance decreased as organics reduction is optimized), then this would have to be taken into account by the EPA in establishing a floor (or floors). The Senate Report indicates that if certain types of otherwise needed controls are mutually exclusive, the EPA is to optimize the part of the standard providing the most environmental protection. S. Rep. No. 228, 101st Cong. 1st sess. 168 (although, as noted, the bill accompanying this Report contained no floor provisions). It should be emphasized, however, that the D.C. Circuit has stated that "the fact that no plant has been shown to be able to meet all of the limitations does not demonstrate that all the limitations are not achievable." *Chemical Manufacturers Association* v. *EPA,* 885 F. 2d at 264 (upholding technology-based standards based on best performance for each pollutant by different plants, where at least one plant met each of the limitations but no single plant met all of them).

All available data for EGUs indicate that there is no technical problem achieving the floor levels contained in this final rule for each HAP simultaneously, using the MACT floor technology. Data demonstrating a technical conflict in meeting all of the limits have not been provided, and, as stated above, based on the available data, there are approximately 64 EGUs that meet all of the final existing source emission limits and at least one EGU that meets all of the final new source emission limits.

[319] Because industry commenters argued that the statute can only be read to allow floors to be determined on a single source basis, commenters offered no view of why their reading could be viewed as reasonable in light of the statute's goals and objectives. It is not evident how any statutory goal is promoted by an interpretation that allows floors to be determined in a manner likely to result in floors reflecting emissions from worst or mediocre performers.

3. Minimum Number of EGUs To Set Floors

Comment: Many commenters indicated that CAA section 112 requires that data from a minimum of 5 units are required to set MACT floors for existing sources. Commenters noted that the EPA's use of less than 5 units for subcategories with greater than 30 units is a legalistic reading of CAA section 112 that could result in such absurd results as using 5 units to set MACT floors for a subcategory with 29 units and data for only 10 units, but using a single unit to set MACT floors for a subcategory with 31 units and data for only 10 units.

Response: The EPA does not agree that CAA section 112(d)(3) mandates a minimum of 5 sources in all instances, notwithstanding the incongruity of having less data to establish floors for larger source categories than is mandated for smaller ones. The literal language of the provision appears to compel this result. CAA section 112(d)(3) states that for categories and subcategories with at least 30 sources, the MACT floor for existing sources shall be no less stringent than the average emission limitation achieved by the best-performing 12 percent of the sources for which the Administrator has emissions information. The plain language of this provision requires the use of fewer data points for large source categories than for small source categories where the Administrator only has emissions information on a small number of units for categories and subcategories with 30 or more sources. Furthermore, commenters contend that Congress could not have intended the floors for a subcategory with 29 sources to be based on 5 sources and a subcategory with 31 sources to be based on less than that number; but we maintain this contention is without merit because 12 percent of 31 is 3.72 (rounded to 4) so the EPA would not base standards for a subcategory with 31 sources on 5 sources even if we had data on all 31 sources in the subcategory. For these reasons, we decline to adopt commenters' position and continue to adhere to the clear statutory directive.

4. Treatment of Detection Levels

Comment: Commenters stated that when setting the MACT floors, non-detect values are present in many of the datasets from best performing units. Commenters provided input on how these non-detect values should be treated in the MACT floor analysis. Some commenters agreed that it is appropriate to keep the detection levels as reported, while certain commenters suggested that the detection levels should be replaced using a value of half the method detection limit (MDL). Many other commenters stated that data that are below the detection limit should not be used in setting the floors, and these data should be replaced with a higher value including either the MDL, limit of quantitation (LOQ), practical quantitation limit (PQL), or reporting limit (RL) for the purposes of the MACT floor calculations. Other commenters stated all non-detect values should be excluded from the floor analysis, or all values should be treated as zero.

Some commenters stated it is necessary to keep the data as reported because changing values would lead to an upward bias. Additional commenters agreed with this basic premise, but suggested that replacing non-detect data with a value of half the MDL is appropriate while still minimizing the bias. They noted that treating measurements below the MDL as occurring at the MDL is statistically incorrect and violates the statute's "shall not be less stringent than" requirement for MACT floors. One commenter also provided a reference for a statistical method based on a log-normal distribution of the data which estimated the "maximum likelihood" of data values; this result is slightly higher than half the MDL.

Some commenters stated that it is necessary to substitute the MDL value when performing the MACT floor calculations. With MDL defined as the lowest concentration that can be distinguished from the blank at a defined level of statistical significance, this is an appropriate value. If MDL values are not reported, one commenter suggested an approach for estimating an MDL equivalent value, but recognized that the background laboratory and test report files may not be available to the EPA in order to derive these estimates.

Most commenters representing industry and industry trade groups argued that either LOQ or PQL values should replace non-detects. The LOQ is defined as the smallest concentration of the analyte which can be measured. These commenters contended that the LOQ leads to a quantifiable amount of the substance with an acceptable level of uncertainty. A few commenters provided calculations showing some of the proposed MACT floors were below the LOQ. Additionally, some of these commenters stated that using LOQ or PQL values also incorporates additional sources of random and inherent sampling error throughout the testing process, which is necessary. These errors occur during sample collection, sample recovery, and sample analysis;

MDL values only account for method specific (*e.g.,* instrument) errors. These commenters contended that the three times the MDL approach discussed in the proposal accounts for some measurement errors but does not account for these unavoidable sampling errors. The commenters also noted that an LOQ is calculated as 3.18 times the MDL, and PQL is calculated as 5 to 10 times the MDL. Many of the commenters in support of using either an LOQ or PQL value ultimately believed a work practice is more appropriate where a MACT floor limit is below either of these two values. They cited CAA section 112(h)(1) which allows work practices under CAA section 112(h)(2) if "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations". These commenters stated that the inability of sources to accurately measure a pollutant at the level of the MACT floor qualifies as such a technological limitation that warrants a work practice standard.

Commenters stated that where the proposed MACT floor is below the LOQ or PQL then that source category has a technological measurement limitation. A few commenters suggested RL values should be used when developing the floor limits. They stated that the RL is the lowest level at which the entire analytical system gives reliable signals and includes an acceptable calibration point. They added that use of an acceptable calibration point is critical in showing that numbers are real versus multiplying the MDL by various factors.

Several commenters stated that all non-detect values should be excluded from MACT floor calculations. They believed that excluding all non-detect values would eliminate any potential errors or accuracy issues related to testing for compliance. Due to inconsistencies of the MDL value reported for non-detect data, one commenter suggested treating all such values as zero. This would provide a consistent approach for setting the floor as well as determining compliance.

Several commenters provided input on the EPA's proposed method of three times the MDL as an option for setting limits. A few commenters in support noted that this approach provided a reasonable method to account for data variability as it took into account more than just analytical instrument precision. Many other commenters argued that this method results in limits which are too low, namely that it is still lower than the LOQ value which they are in favor of as a substitute for any reported non-detect data. Other commenters disagreed with this method and claimed that it would lead to results which introduce a high bias in the floor setting process. A few contended that multiplying by 3 would introduce a 300 percent error into the floor, resulting in a floor that is less stringent than required by the Act. Others suggested that the MDL values are antiquated and already too high and thus it is not appropriate to multiply them by three. Also, a few commenters suggested multiplying the MDL by three would not reflect the actual lower emissions achieved by any source and as such is unlawful under CAA section 112(d).

Response: We agree with many of the comments related to treatment of data reported as detection limit values in the development of MACT floors and emissions limits. As we noted at proposal, the statistical probability procedures applied in calculating the floor or an emissions limit inherently and reasonably account for emissions data variability including measurement imprecision when the database represents multiple tests from multiple emissions units for which all of the data are measured significantly above the method detection level. That is less true when the database includes emissions occurring below method detection capabilities regardless of how those data are reported.

The EPA's guidance to respondents for reporting pollutant emissions used to support the data collection specified the criteria for determining test-specific method detection levels. Those criteria ensure that there is only about a 1 percent probability of an error in deciding that the pollutant measured at the method detection level is present when in fact it was absent. (Reference: ReMAP: PHASE 1, Precision of Manual Stack Emission Measurements; American Society of Mechanical Engineers, Research Committee on Industrial and Municipal Waste, February 2001.) Such a probability is also called a false positive or the alpha, Type I, error. This means specifically that for a normally distributed set of measurement data, 99 out of 100 single measurements will fall within ±2.54 × standard deviation of the true concentration. The anticipated range for the average of repeated measurements comes progressively closer to the true concentration. More precisely, the anticipated range varies inversely with the square root of the number of measurements. Thus, for a known standard deviation (SD) of anticipated single measurements, the anticipated range for 99 out of 100 future triplicate measurements will fall within ±2.54 SD/$\sqrt{3}$ of the true concentration. This relationship translates to an expected measurement imprecision for an emissions value occurring at or near the method detection level of about 40 to 50 percent.

By assuming a similar distribution of measurements across a range of values and increasing the mean value to a representative higher value (*e.g.,* 3 times minimum detection level or 3xMDL), we can estimate measurement imprecision at other levels. For an assumed 3xMDL, the estimated measurement imprecision for a three test run average value would be on the order 10 to 20 percent. This is about the same measurement imprecision as found for Methods 23 and 29 indicated in the ASME ReMAP study for the sample volumes prescribed in the final rule (*e.g.,* 4 to 6 dscm) for multiple tests.

Analytical laboratories often report a value above the method detection limit that represents the laboratory's perceived confidence in the quality of the value. This independently adjusted value is expressed differently by various laboratories and is called LOQ, PQL, or RL. In many cases, the LOQ, PQL, or RL is simply a multiplication of the method detection limit. Commonly used multipliers range from 3 to 10. Because these values reflect individual laboratories' perceived confidence, and, therefore, could be viewed as arbitrary, we decline to adopt the LOQ, PQL, or RL because such approaches in our view would inappropriately inflate the MACT floor standards. Our alternative to those inconsistent approaches is discussed below.

Consistent with findings expressed in reports of emissions measurement imprecision and the practices of analytical laboratories, we believe that using a measurement value of 3 times a representative method detection limit established in a manner that assures 99 percent confidence of a measurement above zero will produce a representative method reporting limit suitable for establishing regulatory floor values.

On the other hand, we also agree with commenters that an emissions limit set from a small subset of data or data from a single source may be significantly different than the actual method detection levels achieved by the best performing units in practice. This fact, combined with the low levels of emissions measured from many of the best performing units, led the EPA since proposal to review and revise the procedure intended to account for the contribution of measurement imprecision to data variability in establishing effective emissions limits. In response to the comments about the

quality of measurements at very low emissions limits especially for new sources, we revised the procedure for identifying a representative method detection level (RDL).

The revised procedure for determining an RDL starts with identifying all of the available reported pollutant-specific method detection levels for the best performing units regardless of any subcategory (*e.g.*, existing or new, fuel type, etc.). From that combined pool of data, we calculate the arithmetic mean value. By limiting the data set to those tests used to establish the floor or emissions limit (*i.e.*, best performers), which in this case is a larger data set than normally available for establishing NESHAP, we believe that the result is representative of the best performing testing companies and laboratories using the most sensitive analytical procedures. We believe that the outcome should minimize the effect of a test(s) with an inordinately high method detection level (*e.g.*, the sample volume was too small, the laboratory technique was insufficiently sensitive, or the procedure for determining the minimum value for reporting was other than the detection level). We then call the resulting mean of the method detection levels the representative detection level (RDL) because it is characteristic of accepted source emissions measurement performance.

The second step in the process is to calculate 3xRDL to compare with the calculated floor or emissions limit. This step is similar to what we have used for other NESHAP including the Portland Cement rule. As outlined above, we use the multiplication factor of 3 to reduce the imprecision of the analytical method until the imprecision in the field sampling reflects the relative method precision as estimated by the ASME ReMAP study. That study indicates that such relative imprecision remains a constant 10 to 20 percent over the range of the method. For assessing the calculated floor results relative to measurement method capabilities, if 3xRDL were less than the calculated floor or emissions limit (*e.g.*, calculated from the upper predictive limit, UPL), we would conclude that measurement variability was adequately addressed with the initial floor calculation. The calculated floor or emissions limit would need no adjustment. If, on the other hand, the value equal to 3xRDL were greater than the UPL, we would conclude that the calculated floor or emissions limit did not account entirely for measurement variability. Where such was the case, we substituted the value equal to 3xRDL for the calculated floor or emissions limit (UPL) which results in a concentration where the method would produce measurement accuracy on the order of 10 to 20 percent similar to other EPA test methods and the results found in the ASME ReMAP study.

We determined the RDL for each pollutant using data from tests of all the best performers for all of the final regulatory subcategories (*i.e.*, pooled test data). We applied the same pollutant-specific RDL and emissions limit assessment and adjustment procedures to all subcategories for which we established emissions limits. We believe that adjusting emissions limits in this manner, which ensures that measurement variability is adequately addressed relative to compliance determinations, is a better procedure than the one applied at proposal, which was based on more limited data. We also believe that currently available emissions testing procedures and technologies provide the measurement certainty sufficient for sources to demonstrate compliance at the levels of the revised emissions limits.

5. Basis for New Source MACT

Comment: Several commenters stated that the proposed limits set for new EGUs do not represent the best performing EGU. The commenters state that the EPA has chosen the strictest limit irrespective of the EGU and that limits for new EGUs should be achievable. According to the commenters, no existing EGU is currently meeting the proposed limits, which will result in a moratorium on the construction of new coal-fired EGUs. Further, commenters state that another result of the EPA's flawed approach is that the proposed standards for new EGUs are so low that adequate test methodologies to demonstrate compliance do not exist. Without accurate testing methodologies, commenters assert that contractors will not guarantee that potential emission control technologies will meet the proposed standards. Without accurate test methodologies and vendor guarantees, commenters believe that financing of new facilities will be virtually impossible to secure which will, in turn, effectively preclude the construction of any new coal-based EGUs.

Commenters also stated that the EPA failed to address cumulative effects of using multiple pollution control devices in determining MACT levels applicable to PM levels. In proposing total PM as a surrogate, commenters believe that the EPA failed to consider or address the antagonistic effects that adding multiple pollution control devices can have on an EGU's HAP emissions. Commenters indicated that EGUs would not be able to comply with the proposed new source HCl limit without adding a scrubber or some type of sorbent injection to control HCl emissions. Adding these HCl control technologies will increase the total PM emissions of these units. According to commenters, because a fabric filter-alone configuration (the basis for the new source PM limit) would not meet all MACT limits, these units may not be the best-performing units.

Response: The EPA disagrees with the commenters' statements that no existing unit is currently meeting the new source limits. The EPA established the new source limits based on data from existing EGUs and there is at least one EGU, based on the data available, that is meeting all three final HAP limits and at least eight EGUs that are meeting one or more of the new source limits. As a result of comments received on the full body of data, the EPA has re-ranked the best performing EGUs and reviewed the new source limits based on the re-ranking where appropriate. Based on the revised ranking, the best performing source for PM has changed and that source now forms the basis for the new source filterable PM limit in the final rule. The source is a coal-fired EGU that includes the entire suite of controls that would likely be required on a new coal-fired source constructed prospectively (*i.e.*, it is a unit with SCR, dry FGD, and FF). Thus, the commenters' concerns are no longer relevant as they relate to PM emissions from coal-fired EGUs.

The EPA also believes that the EGUs serving as the basis for the new source Hg and HCl limits in the final rule are representative of what a new coal-fired EGU would look like to meet all of the requisite regulations applicable to EGUs (*e.g.*, NSPS and the CSAPR) as they also include the entire suite of controls that would likely be required on a new coal-fired source constructed prospectively. The EPA has also taken into account the ability of the various test methods to accurately measure emissions at the levels being demonstrated by the EGUs in the top performing 12 percent in establishing the final limits, and we have determined that there are adequate test methods to measure the regulated HAP at the new source levels.

6. Achievability of Limits

Comment: A number of commenters state that the EPA has chosen the strictest limit irrespective of the unit and that limits for new EGUs should be achievable. According to the

commenters, no existing unit is currently meeting the proposed new source limits, which will result in a moratorium on the construction of new coal-fired units. The commenters state that this regulation goes beyond protecting public health and will impact the country's choice of fuel for energy production. Other commenters state that another result of the EPA's flawed approach is that the proposed standards for new units are so low that adequate test methodologies to demonstrate compliance do not exist. Without accurate testing methodologies, commenters allege that contractors will not guarantee that potential emission control technologies will meet the proposed standards. Without accurate test methodologies and vendor guarantees, commenters believe that financing of new facilities will be virtually impossible to secure, and that this in turn will effectively preclude the construction of any new coal-based units. Commenters maintain that adopting standards effectively banning new coal units amounts to a momentous change in national energy policy without discussion or analysis and far exceeds the EPA's authority.

Some commenters add that the proposed new source MACT standards do not represent rates that have been achieved in practice and are orders of magnitude lower than any of the CAA section 112(g) case-by-case MACT limits established for the most advanced units in the U.S. coal fleet by multiple state agencies.

Other commenters stated that the synergistic impact of multiple controls has not been taken into account in the proposed rules. Commenters argue that circumstances exist with respect to the control of acid gases, which will require scrubbers or other SO_2 controls that add particulate to the flue gas stream, and that added particulate must be removed by PM control devices along with the particulate added to the flue gas for EGUs that need to install ACI for Hg control. Because particulate devices provide a fixed percent reduction of particulate, commenters assert that it is mathematically certain that PM performance will decrease because control of both acid gases and Hg would add PM to the flue gas stream which would in turn decrease performance of the PM control on the relevant mass metric. As a consequence, commenters allege that there is no assurance that sources can meet the EPA's "cherry-picked" floors for acid gases and for Hg by "optimizing" these systems to meet the performance of the floor units because to do so would impact their ability to meet the EPA's similarly "cherry-picked" total PM floor standard.

The commenters state that, for existing sources as with the new source standard-setting approach, a pollutant-by-pollutant approach does not consider what the top performing 12 percent achieve in practice for all pollutants and does not consider the antagonistic effects of the concurrent use of various control technologies. For example, one commenter states that 47 of the 131 sources used to calculate the existing source total PM limit only had PM control but no acid gas or Hg controls that could emit additional PM. According to the commenter, the CAA is clear that standards must be based on actual sources and not the product of a pollutant-by-pollutant determination resulting in a set of composite standards that do not necessarily reflect the overall performance of any actual source. To address these issues, the commenter recommends that the EPA use an approach that more accurately reflects what actual best performing sources achieve.

Response: The EPA disagrees with the commenters' contention that the pollutant-by-pollutant approach to establishing MACT floors is inconsistent with the CAA for the reasons set forth in the response to comments on the EPA's MACT floor setting process. In addition, the EPA established the proposed new source limits based on data from existing EGUs, and there are EGUs that are able to meet the new source limits. To the extent the commenters are concerned that no existing source is simultaneously meeting all of the new sources limits, we note that the EPA has revised the new source standards based on comments and data corrections that industry made to data it incorrectly provided in response to the utility ICR. We have identified at least one source that is meeting all of the new source MACT limits in the final rule.

We disagree with commenters that suggest the proposed new source standards are invalid because they are more stringent than CAA section 112(g) case-by-case MACT limits established by state agencies. As commenters note, states, not the EPA, established the CAA section 112(g) standards, and they did so based on the information available to them. The EPA likewise must establish CAA section 112(d) standards based on the available data. We have considered the available data and information, including the 2010 ICR data, and complied with the requirements of CAA section 112(d) in establishing the standards in this final rule. That the final standards are more stringent than CAA section 112(g) standards issued by certain state agencies has no bearing on the legitimacy of the standards at issue here.

The EPA agrees with commenters that the SO_2 and some Hg controls may add to the PM loading and that it is reasonable to establish the new source standard based on an EGU that has a suite of controls that will be required of any new source. For example, new coal-fired EGUs will be required to comply with the utility NSPS and may have to comply with the CSAPR and other requirements (*e.g.*, SIP or state-only requirements). Commenters are also correct that the proposed new source PM surrogate standard was based on a source that is not like a coal-fired EGU that would be constructed today (*i.e.*, an EGU with only PM control and no SO_2 controls).

The final standard is not based on the source used to establish the proposed limit. As stated above, industry commenters provided data corrections and new data and the EPA considered that new and revised data in establishing the final standards. We re-ranked all the coal-fired EGUs based on the new data. The new ranking of coal-fired EGUs resulted in a change of the source we used to establish the new source PM surrogate standard for non-mercury metal HAP. The basis for the new source limit in the final rule is a unit that has a full suite of controls similar to what would be required for any new coal-fired EGUs (*i.e.*, it is a unit with SCR, dry FGD, and FF). The EPA has identified at least one EGU meeting all of the final new source limits; thus, the EPA does not believe that it is finalizing standards that "ban" new coal-fired generation as indicated by the commenter.

The EPA also disagrees that the final new source standards are so stringent that there are not adequate test methods available to determine compliance with the standards. The EPA has taken into account the ability of the various test methods to accurately measure emissions at the levels being demonstrated by the best performing EGUs in establishing the final limits. This has been done through use of the 3XRDL (discussed elsewhere in this preamble and the Response to Comments document) and through adjustments to the sampling time requirements for certain of the HAP.

7. Comments on Technical Approaches

Comment: Commenters disagreed with the EPA's use of data from multiple units exhausting through a common stack and argued that the EPA unreasonably treated data from multiple

units exhausting through a single stack as multiple data points in establishing the MACT floors. The commenters believe it is improper to count a single data point from a multiple-unit common stack as multiple data points. The commenters state that where two units exhaust through a common stack, the performance is not that of two sources, but only one. The commenters indicate that emissions performance that is actually achieved reflects combined operation, which cannot rationally be split into two parts (data points) because this emissions performance was not achieved by two separate sources. Commenters assert that although it may be acceptable for the EPA to surmise that the combined performance of multiple EGUs and pollution control devices represents an emissions control strategy that could be a best performer, thereby entitling the Agency to use the data at all, the fact is there is only one performer not two. Commenters contend that apart from being inconsistent with applicable MACT case law, counting combined stack emissions as two or more data points is unreasonable because it dampens variability and over-represents the emissions data by creating multiple "performers" or sources when there is in fact only one. Commenters note that in the major-source Industrial Boiler NESHAP, the EPA argued its approach of creating two data points from a single combined stack data point is reasonable because it cannot separate the comingled fraction of the emissions from the different emission points. Commenters state that this is irrelevant, believing that there is no basis to separate these emissions because the MACT floor is based on best performing sources and there is only a single source.

According to commenters, the EPA cannot determine what amount of the overall performance of a combined stack data point is the specific result of the combination. Commenters assert that the EPA also argues that applying the emissions equally to multiple units exhausting through a single stack "accurately represents the emissions of those units on average." Commenters believe that is simply not correct and there is no plausible factual basis for that statement, believing that there is no unit that "achieved" those emissions. Rather, the data represent the combined weighted average of two units, without knowing how either unit actually performed. One commenter also stated that in several instances when a facility operated tandem or multiple EGUs but only submitted a single stack measurement, the EPA used the single stack measurement to represent Hg emissions from the facility's other stacks.

Response: The EPA disagrees with commenters. As in the major-source Industrial Boiler NESHAP, the EPA continues to believe that the emissions from the common stack represent the average emissions of the EGUs exhausting to the common stack and are representative of both EGUs. Commenters have provided no data to support the contention that this assumption is false. In addition, commenters' contention that distinct EGUs (*i.e.,* boilers) are one source if they emit out of a common stack is not consistent with the CAA section 112(a)(8) definition, which clearly applies to the individual boiler units with a capacity of more than 25 MW. It would not be reasonable in light of that definition to consider the emissions from two boilers to a common stack as the emissions of one EGU. The EPA only used data from combined stacks where both EGUs were operating or where the owner/operator certified that no air leakage could occur. The EPA expects that companies will comply with the final rule by conducting testing at the common stack as that is usually where the sampling locations are (rather than in the intermediate ductwork) and will report the results as being for each EGU.

The EPA has reviewed the data based on comments received and does not believe that there are any inconsistencies in the data set used for the final rule. In the MACT floor analysis, the EPA only used data from stacks that were tested or for which test data were provided. These stack measurements were not used to represent emissions from other, non-tested, stacks in the MACT analysis.

8. Alternative Units for Emission Limits

Comment: Several commenters submitted a variety of alternatives to the input- or output-based MACT floor limits as means of establishing the MACT floors. Some commenters suggested emission reductions or removal efficiencies. These commenters suggest that a percent reduction MACT metric be considered as an alternative, and not a substitute, to some of the proposed MACT numerical limits, particularly those that appear too problematic to meet in reality. A necessary data format and protocol could be developed for some HAP, such as Hg, that would allow an appropriate percent reduction alternative to be developed. Commenters believe that the Brick MACT decision stands for the proposition that a MACT level cannot be based on a specific technology; commenters are advocating that a percent reduction format would specify the level or reduction but would not dictate any specific control or methodology.

Comments were also received that some state programs contain Hg emission limits that are more stringent than the EPA's proposed emission limits. The programs of Connecticut, Massachusetts, New Hampshire, New Jersey, and New York were noted. Commenters provided information on these states' Hg emission limits, which often are in the form of either a lb/TBtu format or a percent reduction. Commenters noted that EGUs in these states were in compliance with the state regulations and, therefore, the EPA's emission limits should be more stringent.

Response: The EPA disagrees with the commenters' suggestion that a percent reduction standard should be included in the final rule. The EPA notes that the inability to account for Hg removed from the coal prior to combustion was not the only reason provided for not using a percent reduction format. As noted in the proposal preamble (76 FR 25040), we did consider using a percent reduction format for Hg. We determined not to propose a percent reduction standard for several reasons. The percent reduction format for Hg and other HAP emissions would not have addressed the EPA's desire to promote, and give credit for, coal preparation practices that remove Hg and other HAP before firing because we did not have the data to account for those practices. Specifically, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s). Such an approach would be difficult to implement and enforce. Moreover, we do not have the data necessary to establish percent reduction standards for HAP at this time. Depending on what was considered to be the "inlet" and the degree to which precombustion removal of HAP was desired to be included in the calculation, the EPA would need (*e.g.*) the HAP content of the coal as it left the mine face, as it entered the coal preparation facility, as it left the coal preparation facility, as it entered the EGU, as it entered the control devices, and as it left the stack to be able to establish percent reduction standards. We do not have this type of information.

The EPA believes that an emission rate format allows for, and promotes, the use of pre-combustion HAP removal processes because such practices will

help sources assure they will comply with the proposed standard. A percent reduction requirement would likely limit the flexibility of the regulated community by requiring the use of a control device. In addition, as discussed in the Portland Cement NESHAP (75 FR 55002; September 9, 2010), the EPA believes that a percent reduction format negates the contribution of HAP inputs to EGU performance and, thus, may be inconsistent with the D.C. Circuit's rulings as restated in the *Brick* case (479 F.3d at 880) which say, in effect, that it is the emissions achieved in practice (*i.e.*, emissions to the atmosphere) that matter, not how one achieves those emissions.

The 2010 ICR data confirm that plant inputs likely play a role in emissions to the atmosphere. These data indicate that some EGUs are achieving lower Hg emissions to the atmosphere at a lower Hg percent reduction (*e.g.*, 75 to 85 percent) than are other EGUs with higher percent reductions (*e.g.*, 90 percent or greater). However, we are not sure whether these data accurately reflect the total percent reduction mine-to-stack because we do not have all the data necessary to make that determination. Thus, we proposed to establish numerical emission standards for Hg HAP emissions from EGUs and we are finalizing numerical emission standards. The same issues prevent us from considering percent reduction standards for the other HAP emitted from EGUs.

With regard to the comments relating to some state programs being more stringent than the EPA's proposed limits, the EPA would note that many of the programs identified by one commenter have an "either/or" format for their Hg standards. That is, an EGU can either meet an emission limit (*e.g.*, lb/TBtu) or achieve a percent reduction. The commenter did not note which form of the standard the EGUs were meeting so it is unclear whether the standards are in fact more stringent. In any case, CAA section 112(d) does not mandate that federal standards be more stringent than state requirements for HAP emissions. Furthermore, states are authorized to establish standards more stringent than this final NESHAP so promulgation of this rule will in no way affect a source's responsibility to comply with an otherwise applicable state Hg or other HAP standard.

9. Beyond-the-Floor

Comment: Several commenters stated that the proposed beyond-the-floor Hg limit for low rank coal EGUs is based on too little data and is technically and economically unattainable, noting that the EPA's proposed beyond-the-floor limit is based on only three samples from a single test held at only one EGU, which is not enough data to develop such a limit, especially as more data were available for this EGU in the database. Commenters noted that although this one EGU may have been able to achieve the proposed limit during this one test, the three samples are not adequate to demonstrate the long-term ability of this EGU to meet that limit consistently, let alone the long-term abilities of the top 12 percent of all low rank coal EGUs to meet that limit consistently. Given Texas lignite's particularly high rates of variability of Hg concentration, and the inability to minimize this variability, the commenters believe that the EPA is obliged to have more, not less, data to support the proposed beyond-the-floor Hg limit for low rank coal EGUs. One commenter added that the EPA's decision to require a beyond-the-floor limit for the low rank virgin coal subcategory does not comply with CAA section 112(d)(2). Some commenters also contended that the EPA failed to include the cost of a baghouse in its beyond-the-floor analysis. They note that, according to the EPA, in order to comply with the proposed EGU MACT rule, units will either fuel switch to a lower Hg fuel or retrofit air pollution controls.

Response: The EPA notes that all of the low rank virgin coal-fired EGUs for which data were submitted in response to the 2010 ICR were meeting the Hg floor limit (11 lb/TBtu). Four of the EGUs have ACI systems installed and three of the four EGUs tested were also meeting the beyond-the-floor Hg emission limit of 4.0 lb/TBtu. Those three units were achieving control levels of greater than 95 percent (fuel to stack). The other low rank virgin coal-fired EGUs that are not currently meeting the beyond-the-floor emission limit do not have installed Hg-specific controls. An analysis of the Hg content of the fuel used during the 2010 ICR testing suggests that control in the range of 80 to 90 percent (fuel to stack) would be needed to meet the beyond-the-floor limit of 4.0 lb/TBtu. One low rank virgin coal-fired EGU achieved 75 percent control with no Hg-specific control technology (*e.g.*, ACI).

The EPA believes that its beyond-the-floor analysis is appropriate, including the costs analyzed. The EPA's cost analysis is meant to serve as an average for all sources in the subcategory recognizing that some EGU's costs will be more and some less; EGUs whose costs are higher are not exempted from the regulation. Further, five EGUs in the subcategory are meeting the final beyond-the-floor limit based on available data (*see* the MACT Floor analyses in the docket), and, in any case, CAA section 112(d) does not require that a specified percentage of sources in a category or subcategory be able to meet the MACT standard that is established. This is even truer for beyond-the-floor standards which are set at levels beyond what the average of the best performing sources are achieving in practice and instead based on what is achievable. Commenters have failed to provide any data that supports the contention that some EGUs in the subcategory will not be able to achieve the standards with additional controls.

Comment: Commenters indicated that the EPA has not justified a beyond-the-floor limit for Hg for new IGCC units. The EPA's choice of the beyond-the-floor Hg limit for new IGCCs is not derived from IGCC test data from the 2010 ICR and commenters allege that the EPA has not provided adequate justification for its decision from a technology capability assessment. Commenters note that ACI for Hg treatment of coal-derived syngas is not in use in any operating IGCC plant today, nor can it be used in the same fashion as it is used at conventional coal-fired EGUs. Commenters assert that the EPA also lacks data with respect to new IGCC units, yet the EPA proposed beyond-the-floor MACT limits for new IGCC sources. The commenters assert that the EPA's limits for new IGCC sources are based on beliefs, predictions, projections and design target assumptions. The limits from the 2007 DOE Report referenced in the preamble are based on environmental target assumptions. These IGCC environmental targets were chosen to match Electric Power Research Institute (EPRI) design basis from their Coal Fleet for Tomorrow Initiative. Commenter states that EPRI notes that these were design targets and were not to be used for permitting values. Commenters assert that the EPA has simply not justified its process for going beyond-the-floor for new IGCC units and that, without sufficient justification, the EPA actions are unsupported.

Two commenters provided permit information, based on IGCC units currently under construction, for PM and Hg emissions. One commenter requested that the proposed new MACT floor limit for PM be modified to address the two scenarios for duct burners at IGCC plants, syngas-fired and natural-gas-fired. The commenter requested the 0.050 lb/MWh limit be increased to at least 0.068 lb/MWh

based on gross energy output from the combined cycle generating unit when operated with duct burners fired with syngas. The 0.068 lb/MWh value is consistent with the calculated emission ceiling for its permit to construct for this operating scenario. According to the commenter, there is not sufficient experience with syngas turbines for manufacturers to guarantee performance in the 0.050 lb/MWh range. The 0.0681b/MWh performance basis proposed by the commenter was calculated based on the emission guarantees that the commenter was able to obtain for a turbine fired on the syngas. The commenter also requested that the 0.050 lb/MWh limit be increased to 0.083 lb/MWh based on gross energy output from the combined cycle unit when operated with duct burners fired by natural gas. The commenter indicated that, depending on market conditions, the syngas produced at an IGCC may have more value as a raw material for producing co-products than it would have as duct burner fuel. Where that is the case, the economic viability of an IGCC would be enhanced by firing the duct burners on natural gas and diverting that syngas to manufacture of a co-product. The commenter's air permits are currently based on the use of syngas as duct burner fuel; however, the commenter is currently examining an alternative operating scenario that may result in amendments to the air permits to authorize firing natural gas in the duct burners. Commenter states that preliminary calculations indicate that the PM limit would need to be set at 0.083 lb/MWh gross energy output when operated with duct burners fired with natural gas.

The commenter also noted that there is not sufficient test data to precisely predict the Hg emissions performance of even the best-controlled IGCC units, other than that IGCC Hg emissions are expected to be much less than those for EGUs that directly burn coal. In its permit application, the commenter proposed to establish a new standard for Hg removal in IGCC units by treating the syngas in catalytic reactors. The catalytic reactor system is expected to achieve greater than 95 percent Hg removal using either sulfur-impregnated activated carbon or alumina catalyst. In the absence of actual stack test data, the commenter has had to estimate expected emissions based on engineering estimates of how much Hg may arrive in the syngas routed to the catalytic reactors. Based on these engineering estimates and 95 percent Hg removal in the catalytic reactors, the commenter believes that the resulting Hg emission limit for a state-or-the-art IGCC unit would be 0.003 lb/GWh, which is much less than the Hg emissions for EGUs that directly burn coal.

The commenter notes that IGCC units are still in their infancy. Funding for them will be very difficult or unavailable if there is a regulatory limit below the level that can be supported by vendor guarantees. Given the important role that IGCC units may have in meeting global energy and climate stability goals, the commenter believes it would be a mistake to erect barriers to the implementation of this technology. The commenter stated that the EPA can reevaluate the appropriate levels for future IGCC units after demonstration units which incorporate effective controls have been built and tested.

Response: The EPA is not finalizing the proposed new source standards for IGCC units. As commenters noted, EPA proposed beyond-the-floor limits for IGCC units based on the performance of PC-fired EGUs and solicited data from IGCC units that would represent what a new IGCC could achieve. We received information that there are new IGCC units permitted and under construction. The EPA believes one IGCC unit under construction for which permit data were provided is representative of both current technologies and of IGCC units that will be built in the near-term future. Therefore, the EPA believes these permit levels should be the basis of the new source IGCC emission limits and the Agency is finalizing the PM and Hg limits on that basis, as that source will be required to comply with its permitted limits once constructed and it is a similar source. However, permit limits were only provided for PM and Hg; therefore, the EPA is finalizing the new source limits for acid gas HAP based on data from the best-performing of the existing IGCC units for the respective HAP.

B. Rationale for Subcategories

Many commenters stated that the EPA should have proposed more subcategories, while others believed that too many subcategories were proposed. Many different issues were raised by commenters, and some of the key issues that were considered in the final rule (some of which led to changes in the final rule) include: the technical deficiencies in the definition for the low-Btu coal subcategory; additional subcategorization of the coal-fired EGU population; the need for subcategorization of distillate vs. residual oil-fired EGUS; the need for a limited-use subcategory for EGUs that operate for only a small percentage of hours during a year; and the need for a non-continental liquid oil subcategory for island units that have limited fuel options and other unique circumstances. The comments and the EPA responses are provided below.

In general, the EPA has reviewed the data provided and continues to believe that the coal-fired EGU subcategories proposed are the only ones supported by the data, though we have revised the basis for EGUs designed to burn low rank virgin coal as discussed above. The EPA may not subcategorize by air pollution control technology type as requested by a few commenters. Further, the EPA has reviewed the other suggested coal-fired subcategories and finds no basis for further subcategorization (*e.g.*, based on boiler design, boiler size, or duty cycle).

1. Coal Subcategories

Comment: Commenters noted that although other subcategories had been evaluated, including subcategorization of other coal ranks, no other coal rank subcategorization was proposed. Commenters submit there should be subcategories for the coal ranks of bituminous, subbituminous, and lignite. The commenters noted that such treatment would be consistent with past practice (*e.g.*, CAMR where the differences in the type of emissions of Hg due to the different chemical properties of coal within differing fuel ranks was discussed). Commenters note that activated carbon has been shown to be very effective when used in combination with low chlorine coals (such as western subbituminous coals); however, activated carbons can suffer from poor performance when used with high sulfur coals. Commenters indicate that firing high sulfur coals (especially when an SCR is also used) can result in sulfur trioxide (SO_3) vapor in the flue gas stream. The SO_3 competes with Hg for binding sites on the surface of the activated carbon (or unburned carbon) and limits the effectiveness of the injected activated carbon. But another commenter noted that an SO_3 mitigation technology, such as dry sorbent injection (DSI, *e.g.*, trona or hydrated lime), applied upstream of the ACI can minimize this effect.

Commenters also stated that without further subcategorization the economic impacts on individual Midwestern states will be particularly acute as huge segments of the U.S. coal reserve will be disenfranchised by this rule. According to the commenters, the EPA did not even attempt to legitimately analyze this issue and, thus, in their opinion the Agency's proffered rationale for

declining to further subcategorize based on the acid gas standard is belied by the record. The commenters believe that the EPA needs to better align this rule with its previous position in CAMR and further subcategorize based on coal type.

Other commenters are opposed to any further subcategorization based on coal rank. Because many sources blend several ranks of coal on a regular basis, commenters believe that establishing coal rank subcategories would create numerous opportunities for sources to game the regulations and substantially increase emissions. Commenters stated that there is no need for such an approach since modern pollution controls can accommodate a wide range of coals. These commenters believe that EGUs firing different ranks of coal are not fundamentally different in size, class, or type in a way that impacts emissions or that limits the availability of controls. The commenters believe that emissions of fuel-dependent HAP can be controlled by either changing the fuel prior to combustion or by removing the HAP from the flue gas after combustion. Commenters state that ACI systems, DSI controls, and PM controls are available for installation at units firing sub-bituminous coal and are equally available for units firing bituminous, anthracite, or lignite coal. These commenters also believe that as long as a control option is commercially available, the cost for a particular EGU is irrelevant to the EPA's development of emission standards based on MACT. Commenters stated that subcategories based on coal rank would make a meaningful consideration of fuel switching impossible, contrary to the judicial mandate to consider substitution of materials in setting the floor and the statutory mandate to consider substitution of materials in the beyond-the-floor analysis.

One commenter stated that although they previously supported the subcategorization of coal-fired units on the basis of coal rank, they no longer object to grouping units that burn bituminous and subbituminous coals in a single category because the prior basis for subcategorization no longer exists. The commenter indicated that at the time of CAMR, it was widely recognized that although coal-fired units combusting bituminous coal, with its higher concentration of chlorine and, therefore, ionic Hg, could effectively limit Hg emissions by utilizing existing control technologies such as scrubbers, units burning subbituminous coal could not do so with the same controls because of the coal's higher levels of elemental Hg. The commenter stated that activated carbon was only a fledgling and unproven technology at the time; today, however, activated carbon has been proven, and units burning bituminous and subbituminous coal can achieve the same levels of emissions for Hg and other HAP. Consequently, the commenter believes the prior basis for subcategorization no longer exists and the commenter, therefore, agrees that coal-fired EGUs burning bituminous and subbituminous coals ought to be grouped in a single category.

Response: The EPA disagrees with commenters that additional coal-fired subcategories are warranted and has not provided any in the final rule. Commenters are correct that additional subcategorization was proposed in January 2004. Whether or not such subcategorization was warranted at that time, the EPA believes that the current conditions are such that, even if appropriate at that time, such further subcategorization is not appropriate at this time.

When all of the factors noted by commenters have been reviewed, with the exception of Hg for certain units, as discussed above, the EPA does not believe that the HAP emissions to the atmosphere are sufficiently different from coal-fired EGUs to warrant further subcategorization. There are EGUs firing bituminous, subbituminous, and coal refuse among the top performing units for Hg and EGUs firing bituminous, subbituminous, lignite, and coal refuse are all among the top performers for the acid gas HAP and non-mercury metallic HAP indicating that the MACT floor limits established based on these units are achievable by units burning all ranks of coal.

As noted by commenters, ACI, not fully developed in 2004, is now able to effect Hg control levels on subbituminous coals such that similar emissions to the atmosphere may be achieved as those achieved by higher-chlorine bituminous coals when FGD systems are used or by coal refuse EGU with less controls. Thus, in looking at the total system, similar emissions to the atmosphere are achieved by all of these coal ranks. The EPA has addressed elsewhere in this document its rationale for not subcategorizing by coal chlorine content. The EPA does not believe that any fundamental discrimination between coal ranks will occur as a result of the final rule, though clearly some sources will be required to install greater controls to comply with the final standard. We maintain that such result is consistent with the intent of CAA section 112 standards, which are not intended to have an outcome whereby all sources can comply with final standards without any action.

The EPA agrees, in theory, that EGUs are designed around a basic set of coal characteristics. However, the 1999 ICR demonstrated that numerous EGUs have conducted trial burns and gained sufficient experience such that co-firing blends of various coal ranks is now common practice. In fact, the EPA believes that such blends may be modified daily, depending on the characteristics of the coal being burned and on the level of generation needed. The extent of blending, and the ability to switch the blends on short notice, does not lend itself (or, in fact, argue for) additional subcategorization.

The EPA disagrees with any assertion that the EPA ignored possible subcategorization approaches or that it has insufficient data upon which to base or evaluate various subcategories. The EPA fully examined the record, which demonstrates that coal-fired EGUs, with the exception of certain units for Hg, have similar HAP emissions profiles and that similar control approaches are available to such EGUs. Although commenters suggested additional subcategories were warranted, they failed to provide sufficient data to support their proposed alternative subcategories. As noted elsewhere, the EPA does not disagree with commenters that there are some differences in EGUs. However, the EPA does disagree with commenters that those differences result in differences in emissions to the atmosphere such that additional subcategorization is justified.

Failing to demonstrate that coal-fired EGUs are different based on emissions, the commenters turn to economic arguments, asserting that failing to subcategorize will impose an economic hardship on certain sources. Congress precluded consideration of costs in setting MACT floors, and it is not appropriate to premise subcategorization on costs either. See S. Rep No. 101–228 at 166–67 (5 Legislative History at 8506–07) (rejecting the implication that separate categories could be based on "assertions of extraordinary economic effects"); *see also NRDC* v. *EPA* 489 F.3d 1364 (D.C. Cir. 2007) (holding that EPA properly declined to create a subcategory for a particular source and rejecting the argument that the source may have to incur more costs to comply with the rule without such subcategory).

The final limits are based on EGUs currently operating with available controls. As noted above, the record shows that the various types of EGUs are represented in the floors, with the exception of certain units for Hg, which

indicates that the levels are achievable by such units. Thus, the data actually show that the MACT standards are achievable for a wide variety of EGUs.

In addition, the EPA believes it has fulfilled the CAA section 112(c)(l) directive that "[t]o the extent practicable, the categories and subcategories listed under this subsection shall be consistent * * *" with those of CAA section 111, notwithstanding commenters assertion to the contrary. The decision on whether to directly align CAA sections 112 and 111 subcategories is discretionary and EPA has reasonably exercised its discretion in declining to create additional subcategories for coal-fired EGUs based on the record, with the exception of certain sources for Hg.

Finally, the EPA disagrees with the commenters that suggest that EPA lacks the legal authority to consider material inputs when considering subcategories. We agree, however, that material inputs must be considered when establishing MACT standards for the subcategories that are established. We also believe a meaningful consideration of fuel switching can occur even if sources are subcategorized based on fuel inputs because EPA considers fuels switching in evaluating potential beyond-the-floor alternatives.

Comment: One commenter stated that the EPA should establish an existing source acid-gas subcategory for high sulfur or high chlorine coals because the same factors that the EPA relied on to support a low rank virgin coal subcategory for Hg are also present in the high sulfur or high chlorine coal context. The commenter stated that the data indicate that even well-controlled units burning high sulfur coals would not be in the top performers for acid gases even at removal rates of 95 or 96 percent. The commenter added that absent such a subcategory, about 12 percent of coal deliveries (2005 data), and the vast majority of coal shipped from the states of Indiana, Ohio, and Illinois (2008 data), would become unusable. The commenter expressed support for the alternative SO_2 standard for units unable to meet the HCl standard; however, the commenter also believed that it is appropriate to establish a coal chlorine or sulfur content-based subcategory for the alternative SO_2 standard. The commenter stated that coal testing data indicate a clear break in chlorine concentrations in the coals burned by EGUs, as well as in sulfur content. The commenter indicated that there are factors supporting a high sulfur or high chlorine coal subcategory that are similar to those that the EPA relied upon to support a Hg subcategory for low rank virgin coal. According to the commenter, the EPA's key rationale for a Hg subcategory for low rank virgin coal was that no low rank virgin coal-fired unit appeared in the "top performing 12 percent of sources, indicating a difference in the emissions for this HAP from these types of units." The EPA did not establish other subcategories because "the data did not show any difference in the level of HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for other HAP." The commenter indicated that the EPA does not need emissions data to know that even well-controlled units burning higher sulfur coals would be unable to meet the alternative SO_2 emissions rate, and would therefore also not appear in the top 12 percent of performing units.

Response: The EPA disagrees with commenters that subcategories should be established for high sulfur and high chlorine coals. It appears from the comments that it is not in fact the chlorine content that is at issue but the sulfur content of the coal. Commenters state that they are unable to meet the HCl limit, but they only provide information indicating it would be difficult to meet the alternative equivalent SO_2 limit. In fact, our data show that coals with chloride contents as high as 2,100 ppm (0.16 lb/MMBtu) were burned by EGUs making up the MACT floor pool of sources for the final HCl emission limit and that the best-performing unit was burning coal with a maximum chloride content of 1,200 ppm. The median chloride level for bituminous coals identified from data submitted through the 1999 ICR was 1,030 ppm so we believe that the coals represented in the MACT floor pool indicate that the final limits are achievable with high-chlorine coals. We have determined that HCl removal is very effective using a number of different types of FGD systems. Absent information demonstrating that sources are unable to meet the proposed HCl limit due to the chlorine content of the coal, we believe it is unnecessary and inappropriate to consider subcategorizing based on chlorine content in the coal.

In addition, as noted above, the SO_2 limit is an alternative equivalent standard that is available to sources that have an SO_2 control and CEMS and operate the controls at all times. The EPA did not provide the alternative equivalent standard for sources that could not meet the HCl limit as one commenter suggests; instead, we provided the standard as a convenience and cost saving measure to EGUs with installed FGD systems because we recognize that many EGUs have SO_2 CEMS. Sources are required to comply with the HCl limit as a surrogate for all the acid gas HAP or the SO_2 limit as an alternate equivalent standard. Commenters have not demonstrated that they are unable to meet the HCl standard and our data show that the standard is achievable even for high chlorine coals.

Comment: Several commenters supported the development of a separate subcategory for fluidized bed combustors (FBC) or circulating fluidized bed (CFB) EGUs. The commenters encouraged the Agency to consider subcategorization of FBC EGUs for Hg emissions noting that the industry has long contended that the design, construction, and operation of FBCs are different than conventional boilers and that FBCs employ fundamentally different processes than conventional PC-fired EGUs. The selection of an FBC unit over a conventional PC boiler is driven in large part by fuel characteristics. The commenters assert that, as a result, the emissions profile of FBC units generally differ from conventional PC boilers because FBC units more advantageously combust waste coals, as well as coal blends with other carbonaceous material. The commenters stated that the EPA did not discuss the design differences between FBC units and PC units in the preamble to this proposed rule unlike what the Agency did when it previously proposed Hg MACT limits in January 2004. Commenters state that, for these reasons, FBC units can be considered a distinct type of boiler.

The commenters noted that an examination of the 40 "best performing" units for Hg emissions in the proposed MACT floor spreadsheet showed that 14 of those units are FBC units. The commenters maintained that had FBC units performed as well as conventional PC boilers, 2 units would have been expected to be in the top 40. The commenters allege that the far higher percentage of FBCs in the top 40 leads to the conclusion that these units are different from conventional PCs with regard to Hg emissions and, as a result, should have been placed in their own subcategory. Further, commenters noted that the largest FBC has a nameplate capacity of about 300 MW while the largest conventional boilers have nameplate capacities of around 1,300 MW.

The commenters stated that FBCs combust relatively large coal particles in a bed of sorbent or inert material at a lower degree of combustion efficiency.

Fluidized bed units operate at less than half of the temperature of a conventional boiler and have much longer fuel residence times. Conventional boilers pulverize coal to a very fine particle size to maximize combustion efficiency and minimize unburned carbon. As a result, the commenters noted that FBCs typically have higher levels of unburned carbon present in the ash, which behaves much like activated carbon and helps promote more efficient Hg removal. Accordingly, commenters maintain that Hg emissions of FBC boilers and PC boilers are statistically different, with emissions from FBCs significantly lower than those from PC boilers. According to commenters, this statistically significant difference in the Hg emissions profiles for these two distinct boiler technologies argues in favor of the creation of a separate subcategory for FBCs, as there is no control technology that PCs could install that would result in emissions reductions similar to those achieved by FBCs. The active quantity of calcium oxide (lime-CaO) available in a FBC boiler is also orders-of-magnitude greater than compared to a PC boiler, whose alkalinity is derived solely from the coal's mineral content. Significantly higher CaO can alter the process chemistry in the boiler, including the oxidation levels of Hg.

One commenter stated that the EPA properly declined to subcategorize units based on design type where there is no indication that any physical distinctions among unit designs have a meaningful and substantial impact on HAP emissions. The commenter indicated that it would be inappropriate to subcategorize FBCs because there is no evidence to support a determination that FBC design is responsible for a unit falling in or out of the top 12 percent for a particular HAP.

Response: The EPA acknowledges that there are design and operation differences between conventional PC-fired EGUs and FBC/CFB EGUS; however, the commenters are incorrect in asserting that the HAP emissions levels and characteristics are sufficiently distinct from other coal-fired EGUs to support subcategorization. Further, commenters fail to note that FBC EGUs were not subcategorized in CAMR even though, as commenters note, such design and operation differences were cited there. The fact that FBC units operate at lower temperatures is of no consequence as they still operate at temperatures high enough to vaporize Hg.

Commenters assert that FBC units are disproportionately represented among the best performers, with the inference being that they were selected to test in the 2010 ICR because of their boiler design. However, FBC EGUs were not specifically selected as best performers for Hg, as EPA did not select any EGUs based on a determination that they were best performers for Hg (as noted elsewhere, we had no basis for selecting EGUs as being best performers for Hg), and to the extent CFB units were selected in the 2010 ICR, they were selected because we determined they were best performers for non-mercury metallic HAP, acid gas HAP, or organic HAP or because they were randomly selected among the non-best performers for those three HAP groupings. Thus, the CFBs were selected for testing under the 2010 ICR based not on their boiler design but, rather, based on the age and on their PM and FGD control systems (as noted in the Supporting Statement for the 2010 ICR). As many FBC EGUs, including CFB EGUs, are relatively new, they were included in the non-mercury metallic HAP group selected for testing (because their PM controls were among the 175 newest), the acid gas HAP group selected for testing (because FBC was considered to be an FGD system and the units were among the 175 newest), and organic HAP testing (because they were among the newest and, thus, determined to be among the most efficient).

The effect on Hg emissions is not what commenters suggest because, although, as noted by commenters, FBC units may be found among the better performers (among the top 10 EGUs) on the Hg MACT floor spreadsheet, they are also found in the range of 221 to 226 EGUs (of 393 data points). The fact that FBC units have "vastly dissimilar ash properties" that may contain higher levels of lime or unburned carbon in the fly ash than conventional PC EGUs does not indicate that the overall system behaves any differently with regard to emissions to the atmosphere (the key metric) than a conventional PC EGU with add-on controls. The asserted higher levels of unburned carbon result in a range of effectiveness of Hg control that is similar to that of ACI found on PC EGUs; such ACI control may be found on EGUs that are among the better performers as well as on EGUs as low as 369 on the list of data points. Thus, the EPA disagrees that FBC units are disproportionately represented in the Hg floor and that their inclusion is somehow inappropriate or leads to skewing of the analysis.

All types of coal-fired EGUs other than those we subcategorized are represented in the MACT floors for Hg and all types of EGUs are represented in the floors for the non-mercury HAP. Fluidized bed combustion EGUs are not an exception and such EGUs are found across the range of top performing EGUs for all of the HAP categories: Acid gas, non-mercury metallic, and Hg. In addition, any assertion that non-FBC EGUs are unable to meet the final standards because FBC EGUs are included in the same subcategory (or vice versa) is plainly refuted by the fact that EGUs of all types are currently meeting one or more of the final standards. Thus, the EPA finds no basis for subcategorizing FBC EGUs.

Further, as noted below, the EPA does not believe there is a basis for subcategorizing small EGUs, either FBC or PC. In addition, the data have been re-evaluated based on comments received and an FBC unit is not the basis for the new source Hg MACT floor.

Comment: Many commenters stated that the EPA should have considered additional subcategorization schemes, including one based on EGU size. Commenters noted that one of the factors that the Administrator can consider under CAA section 112(d)(1) in making subcategorization decisions is unit size. Commenters stated that an analysis of the 2010 ICR data showed a statistical difference between EGUs with a capacity of 100 MW or less and EGUs above 100 MW; other commenters suggested that the cut-off range should be 125 MW. Although large in number (about 27 percent) of all EGUs, these small EGUs only comprise about 5 percent of the coal-fired capacity in the U.S. Thus, commenters assert that if different MACT limits are set for this subcategory of EGUs, it will not have a significant impact on the health effects of HAP emissions. Commenters noted that although emission rates from such small EGUs are greater than those found in the large unit fleet, their contribution to the total EGU emissions is not significant. The costs associated with coming into compliance with the proposed rule by installing new controls would be proportionally much higher for these small EGUs than larger EGUs according to the commenters. The commenters allege that this would force the retirement of generation capacity and threaten electrical reliability without appreciable benefit to the environment.

One commenter stated that in general, the nature of many public power facilities differs from the general population of coal-fired power plants. Public power units tend to be smaller in size, and are often space-constrained by growth in the community surrounding the generating unit since its initial construction. These limitations restrict the ability of these EGUs to achieve the same performance levels of larger,

unconstrained EGUs; and, for those EGUs that can comply with the proposed standards, the installation of controls sharply increases the cost of compliance. The commenter stated that the EPA did not adequately subcategorize to accommodate many small- and medium-sized public power utilities. In particular, the EPA did not avail itself of the opportunity to use a public power electric utility subcategory, rural subcategory, or fuel type subcategories. Other commenters endorsed the establishment of a less than 100 MW subcategory that would reduce the costs of the proposed rule significantly, but only affect 5 percent of the total electric utility sector, and help minimize retirement of uneconomical plants.

One commenter stated that the EPA properly recognized that subcategories based on unit size would be inappropriate because the proposed emission limits are in terms of lb/MMBtu or lb/TBtu and noting that an EGU's total nameplate capacity is wholly unrelated to its ability to achieve the proposed limits. Another commenter opposed any proposal to subcategorize units below 100 MW. The proposed rule does not apply to units less than or equal to 25 MW, and this commenter believed that this is a sufficient threshold for applicability.

One commenter stated that the EPA could establish subcategories for the purpose of temporarily exempting, for example, a subcategory of utilities that meet the definition of small entity for purposes of the proposed rule. The temporary exemption would sunset on a date certain (e.g., 3 years from the effective date of the rule) at which point the sources in the subcategory would become subject to the rule, and a compliance timetable would start to run. The commenter believed that this time-staged promulgation and compliance proposal would greatly increase the chance that the control measures could be added in an orderly and efficient manner with minimal disruption to power markets and grid reliability.

Response: The EPA agrees with commenters who stated that an EGU's size is totally unrelated to its ability to comply with the final concentration-based limits. The EPA examined the size of units within the respective MACT floor pools of sources and found units ranging in size from 25 to 1,320 MW in the HCl floor pool, from 25 to 869 MW in the non-mercury metallic floor pool, and from 47 to 544 MW in the Hg floor pool. Thus, we find no more difference between a 25 MW EGU and (e.g.) a 500 MW EGU than we do between a 500 MW EGU and a 1,300 MW EGU and reaffirm our position that the MW capacity of the EGU is not a determining factor in its emissions. Further, the EPA believes that units of all sizes are owned by both large and small entities.

The EPA examined the effect if EGUs less than 125 MW were subcategorized for Hg. The resultant MACT floor for these EGUs would be 1.0 lb/TBtu on a 30-boiler operating day rolling average, a level more stringent than that developed for the >8,300 Btu subcategory as a whole. We do not believe that this is what commenters envisioned when suggesting such a subcategory but we believe it confirms our analysis of the data that indicates, as noted, these units are controlled in the same manner as other, larger EGUs, such that additional subcategorization is not necessary or reasonable. Further, based on the number of EGUs less than 125 MW in the HCl and PM MACT floor pools, we believe that a similar analysis for HCl and PM would lead to similar or more stringent standards than without the additional subcategory. Thus, units of all sizes are capable of achieving the proposed limits and the EPA is not finalizing a subcategory based on unit size in the final rule.

The CAA authorizes EPA to subcategorize based on "classes, types, and sizes of sources." The EPA does not believe that this provision permits subcategorizing sources based solely on their status as small entities for several reasons. As a threshold matter, commenters provided no information to suggest that EGUs at small entities are different from EGUs owned by other entities. Instead, the commenters' justification for such a subcategory was that the costs to comply with the standards make it more difficult for small entities; thus, the basis is essentially a cost basis and we do not think that is consistent with the statute. Moreover, the legislative history of CAA section 112(d) supports EPA's interpretation that subcategories cannot be based on the cost of compliance. *See* S. Rep No. 101–228 at 166–67 (5 Legislative History at 8506–07) (rejecting the implication that separate categories could be based on "assertions of extraordinary economic effects").

In addition, the EGUs owned by small entities use the same type of fuel as other units, have the same type of combustor designs, and can use the same types of controls, and so there is no difference in the HAP emissions from such units. So, even if we believed a subcategory based on small entities was consistent with the statute, we would decline to include such a subcategory.

Therefore, given the language of CAA section 112(d), the legislative history, and the available information, EPA is not creating a separate subcategory for EGUs owned by small entities.

In addition, the D.C. Circuit has clearly stated that the EPA does not have the statutory authority under CAA section 112 to extend compliance dates past the 3-year maximum compliance time authorized in CAA section 112(i)(3)(A) except consistent with CAA sections 112(i)(3)(B) and 112(i)(4). *See NRDC* v. *EPA*, 489 F.3d 1364, 1374 (D.C. Cir. 2007) (finding that "Congress enumerated specific exceptions to the 3-year maximum, which indicates that Congress has spoken on the question and has not provided the EPA with authority under subsection 112(i)(3)(B) to extend the compliance date * * *") (citing also CAA section 112(i)(4)). The EPA may not alter the compliance date based on size or ownership considerations and, thus, we are not providing a separate compliance date for different groups of EGUs in the final rule.

Comment: One commenter stated that the EPA should establish a subcategory consisting of EGUs that had received air construction permits but had not yet commenced construction as of the date of the EPA's proposed rule. The commenter believed that such a category would be justified because a substantial amount of time, money, and effort has been invested in these units. The commenter asserted that imposing new source standards on these EGUs for which the EPA's proposed rule had not been anticipated during their permit consideration would unreasonably and arbitrarily impose additional costs and burdens on these projects and would likely threaten the viability of many of them. The standards for this subcategory would be based on the anticipated performance of these units (as reflected by the permitted case-by-case emission levels), ensuring a reasonable and appropriate level of HAP control without unreasonably and arbitrarily interfering with the development of these units.

Response: Clean Air Act section 112(a)(4) defines a new source as "a stationary source the construction or reconstruction of which is commenced after the Administrator first proposes regulations under this section establishing an emission standard applicable to such source." The EPA's regulations implementing the CAA section 112 General Provisions define "commenced" to mean "with respect to construction or reconstruction of an

affected source, that an owner or operator has undertaken a continuous program of construction or reconstruction or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or reconstruction." *See* 40 CFR 63.2.

The EPA is constrained by the definition of "new source" such that any source that "commenced" construction after the May 3, 2011, proposal date is considered a new source under the statute and the source must comply with the new source standards even if the source received a final and legally effective CAA section 112(g) permit before proposal. It is unclear from the comments whether the sources identified in the comments have commenced construction as defined in the regulations; however, the identified sources are existing sources, not new sources, under the final rule if construction was commenced prior to the proposal date.

Under the final rule, new sources must comply with the standards on the date of promulgation or at startup, whichever is earlier, and existing sources have 3 years to come into compliance with the final standards. Pursuant to the EPA's regulations at 40 CFR 63.44(b)(1), however, we may provide in a final CAA section 112(d) standard a specific compliance date for those sources that obtained a final and legally effective CAA section 112(g) case-by-case MACT standard and submitted the information required by 40 CFR 63.43 to the Agency before the close of the comment period. The EPA does not believe it has received such information during the comment period and we are not establishing a separate specific compliance period for sources that obtained final and legally effective CAA section 112(g) standards prior to promulgation of the final rule. In the absence of EPA action on this issue, state Title V permitting authorities are required to "establish a compliance date in the [title V] permit that assures that the owner or operator shall comply with the promulgated standard [ ] as expeditiously as practicable, but not longer than 8 years after such standard is promulgated * * *" 40 CFR 63.44(b)(2). Sources with final and legally effective section 112(g) standards should work with their permitting authorities to determine the appropriate compliance date consistent with the EPA regulations.

Comment: One commenter stated that in accordance with CAA section 112(d)(1), based on the government-to-government relationship of the Navajo Nation and the U.S. government, and consistent with the right of sovereignty and self-determination of the Navajo Nation, it may be appropriate to classify EGUs on tribal lands in a different subcategory from those on non-Indian lands. The commenter stated that in accordance with the distinctive status of Indian lands, based on principles of tribal sovereignty and self-determination, the government-to-government relationship, and the flexibility of federal agencies mandated under E.O. 13175, the EPA should classify sources on tribal lands as a unique subcategory of EGUs for which emission standards for NESHAP should be set pursuant to CAA section 112(d)(3).

Response: Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. In the preamble to the proposed rule, the EPA further explains that any basis for subcategorizing (*e.g.,* class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not agree that a subcategory based on location on Tribal lands is consistent with the statutory authority to subcategorize, and commenters do not explain why emissions would be different for EGUs located on Tribal lands. Absent that showing, EPA believes it would not be appropriate to subcategorize units even if we believed such a subcategory is consistent with the statute. CAA section 112 imposes specific requirements with respect to the methodology that the EPA must use in establishing emission standards for HAP, including Hg emissions from EGUs. Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. The EPA believes, that any basis for subcategorizing (*e.g.,* class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance.

However, the EPA is sensitive to the commenters' concerns and particularly recognizes the significance of Navajo Generating Station to the Central Arizona Project and the water delivery to tribes. As a result, EPA has been consulting with affected Indian tribes and working closely with other federal agencies, including the Department of the Interior, on these issues and intends to work with tribal and other authorities to ensure a smooth transition and address specific issues as they arise.

2. Oil Subcategories

Comment: Several commenters stated that distillate oil, and in particular ultra-low sulfur diesel (ULSD) oil, has fuel characteristics closer to that of pipeline gas than to residual oils. The metals, as well as the ash and nitrogen content, of distillate oils are very low, and the sulfur content of ULSD is approximately the same as that of pipeline natural gas. The commenters state that distillate oil is a more refined product than residual oil and, thus, burns cleaner. According to commenters, separating liquid oil-fired EGUs into two subcategories (distillate and residual oil) would be consistent with the discussion of subcategory differentiation in the rule's preamble which indicates that the division of a category into subcategories is justified if the two subcategories have very different emissions, which is true for distillate vs. residual oils. Distillate and residual oils are also differentiated by their operating requirements. Some commenters stated that as a consequence of the mechanical differences between boilers designed for residual oil vs. distillate oils, and between the fuel-handling requirements for the different fuels, it is not possible to interchange oil types without significant modifications to the oil storage tanks, transfer pumps, piping and valves, flow control systems, burners, and burner control systems. Commenters also noted that some of the EGUs in the EPA's liquid oil-fired database were mischaracterized with regard to the type of oil burned during the 2010 ICR testing.

Some commenters alleged that by combining distillate and residual oil into a single MACT category, the resultant MACT standards cannot be satisfied by a boiler firing residual oil without substantial add-on controls. The commenters asserted that creation of separate subcategories for liquid oil-fired units that distinguish between residual and distilled oil would render the standards more achievable for distinct subcategories of EGUs and reduce the number of potential plant closures while still advancing the goal of reducing overall emissions. These commenters contend that MACT floors should not be used to eliminate whole classes of existing EGUs through mathematical floor calculations based on data from uncontrolled units and combining boiler subcategories that are not capable of accommodating a different fuel.

One commenter stated that the EPA should not subcategorize liquid oil-fired EGUs based upon different grades of liquid oil. Although different grades of liquid oil may vary in their heat contents or viscosities, the commenter maintained that there is no indication in the rulemaking record that any physical

distinction among units burning different grades of liquid oil affects the nature or characteristics of emissions in a way that impacts the availability of controls. According to the commenter, both distillate and residual oil-fired units can apply similar control technologies to reduce HAP emissions, and EGUs firing these fuels do not have physical distinctions that prevent controls from operating effectively. The commenter believes that fuel switching is an appropriate control technology and is available for liquid oil-fired sources. Residual fuel oil contains higher levels of contaminants, including HAP, than distillate oil, and because a regulated entity can readily burn cleaner distillate oil in lieu of residual oil, it is inappropriate to subcategorize based on the distillation fraction of the liquid oil. Thus, according to the commenter, the grade of liquid-oil fuel does not provide a reasonable basis for subcategorizing various groups of liquid oil-fired EGUs. Another commenter alleges that the EPA did not list distillate oil-fired EGUs in the 2000 Finding.

Response: The EPA has reviewed the data and determined that it is not necessary to subcategorize distillate vs. residual oil. Commenters had noted that the EPA's MACT Floor Analysis spreadsheet at proposal had erroneously assigned the oil type used during testing for some boilers. The EPA reviewed the data and determined that the submitting companies had entered the data incorrectly, or had indicated that two types of oil were fired in different parts of the 2010 ICR responses. The EPA contacted all of the companies with oil-fired EGUs in the 2010 ICR to confirm the oil used during testing. Upon review of these data, it became apparent that units using residual oil with ESPs or distillate oil without control were the best-performing oil-fired EGUs for PM and the HAP metals. Further, although emissions of HAP from distillate oil-fired EGUs are generally lower than those from residual oil-fired EGUs, EGUs burning distillate oil appeared to have higher emissions of some HAP but lower emissions of others.

In addition, the EPA does not agree that distillate oil-fired EGUs were not listed in the 2000 Finding. We believe it is inappropriate to exclude distillate oil-fired EGUs from regulation under the final rule because the Agency did not make a distinction when listing the oil-fired units.

The EPA also disagrees with commenters that by providing the distillate vs. residual oil subcategories as requested, the resultant standards would be more achievable. Were the EPA to subcategorize distillate oil from residual oil, the users of distillate oil would have no means of compliance other than obtaining "compliance" oil from their distributor (which was not indicated as an option by any commenter) or converting to natural gas and being removed from the subcategory. With no further subcategorization, oil-fired EGUs have the option of installing an ESP or converting to distillate oil for compliance. Commenters did not contend that it was impossible to convert to distillate oil, only that it would require plant modifications. Installing controls would also require plant modifications so sources will be able to evaluate the options and determine the most cost-effective option to comply with the final rule. CAA section 112 is intended to be a technology-forcing statute, and, because both distillate oil- and residual oil-fired EGUs were among the best performing sources in the floor and both types are meeting the final standards, we cannot reasonably conclude that the HAP emissions characteristics of these similar types of units are distinct. Therefore, the EPA is not establishing separate subcategories for distillate and residual oil-fired units in the final rule.

3. Limited-Use Subcategory

Comment: Several commenters stated that EPA should establish a limited-use subcategory for liquid oil-fired EGUs that are required to burn oil during periods of natural gas curtailment. One commenter stated that under New York State Reliability Council Rules, their facility is required by the New York Independent System Operator (NYISO), for reliability purposes, to maintain the capability to burn oil and actually burn oil, from time to time, at varying load levels to help avoid or avert potential natural gas shortages in New York City. The requirements to burn oil under this program are mandatory and are not within the commenter's discretion. The reliability rules require that the commenter's EGUs maintain their co-firing capability to respond to unplanned, emergency scenarios by operating on oil during required minimum oil burn periods, typically 25 percent oil/75 percent natural gas. The commenter noted that operation using oil at other times or on 100 percent oil during reliability operation periods occurs very infrequently; with natural gas expected to become more available in future years, such an operating scenario will become less likely. However, while the reliability rules remain in place and commenter's boilers are required to operate under his regimen, the commenter believed that it is essential that it be able to do so.

Other commenters noted that requiring installation of emission controls on oil-fired units that operate at a 10 percent oil-fired capacity factor or less is nonsensical and will result in little environmental benefit. Commenters contend that low-capacity factor units emit significantly less HAP than even well-controlled oil-fired units with much higher capacity factors. In addition, commenters allege that stack-testing at such units would be equally impractical and, in addition, would likely require the unit to operate on oil (and emit HAP just for the test) when it would otherwise be off-line or operating on natural gas.

Response: As stated above, after considering comments received, we are establishing a limited-use subcategory for liquid oil-fired EGUs with an annual fired capacity factor of less than 8 percent averaged over each 24-month block period after the compliance date.

At proposal, we solicited comment on establishing a limited-use subcategory for liquid oil-fired EGUs:

> EPA is also considering a limited-use subcategory to account for liquid oil-fired units that only operate a limited amount of time per year on oil and are inoperative the remainder of the year. Such units could have specific emission limitations, reduced monitoring requirements (limited operation may preclude the ability to conduct stack testing), or be held to the same emission limitations (which could be met through fuel sampling) as other liquid oil-fired units. EPA solicits comment on all of these proposed subcategorization approaches.

As stated above, the EPA did not have sufficient information on limited-use liquid oil-fired EGUs upon which to base a subcategory at proposal. Some sources required to test under the ICR did not submit the data until after proposal. Commenters indicated that their units are different because many of them are only called to service to address reliability issues associated with, for example, natural gas curtailments. The commenters further indicated that their units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shutdown periods (*e.g.*, they are often only required to run for a couple of hours). These factors would lead to differences in the emissions characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited times that these limited use oil-fired units operate.

Based on comments received and our own analysis, we are finalizing a subcategory for limited-use liquid oil-

fired EGUs as indicated elsewhere in this preamble. We find that these units constitute a different class and type of units because they are generally only used to address reliability issues associated with, for example, natural gas curtailments, and because they in fact only run for very limited periods in a year on a seasonal basis.

Although some commenters indicated a prevalence of natural gas/oil co-fired EGUs, the EPA also understands that there are other liquid oil-fired EGUs that do not co-fire natural gas but that could be subject to mandatory operation during periods of natural gas curtailment in their operating area if sufficient non-natural gas capacity is not available. Based on a review of units that report oil use to EPA, in 2010 there were 228 liquid oil-fired EGUs with a capacity factor of less than 5 percent and an additional 10 units with a capacity factor of between 5 percent and 10 percent. Only 2 of these units have capacity factors between 5 percent and 8 percent. This subcategory applies only to oil-fired EGUs that operate on oil alone and act as peaking units, as they generally address reliability issues. We are establishing the capacity factor threshold of 8 percent averaged over each 24-month block period after the compliance date.[320] In addition, as discussed below, we are establishing work practice standard for this subcategory in lieu of numeric emission standards.

Commenters that requested a subcategory for these units noted the dichotomy of establishing a NESHAP to reduce emissions of HAP to the environment while at the same time requiring an EGU to run for the sole purpose of conducting emissions testing and thereby emitting those same HAP. Because the operation of these units is infrequent and unpredictable, performing testing to demonstrate that emission limits are being met requires the sources to be scheduled to be operated merely for the purpose of performing testing. We realize that similar situations occurred in the gathering of emissions data through the 2010 ICR. However, unlike the case of one-time testing on a limited number of these units, such testing would be mandatory on a yearly basis for all of the EGUs upon the effective date of the final rule. Because requiring testing under this rule would in many cases require operators of these EGUs to schedule operation of these EGUs at times they would not otherwise run, it would result in both extra cost related to the testing as well as extra emissions; therefore, the Agency believes that it is technically and economically impracticable to monitor emissions for these EGUs, and that they should be subject to work practice standards that would not require emissions monitoring.

The annual average capacity factor would be calculated on a 24-month block period, commencing with the compliance date of the final rule. For example, assuming a March 1, 2015, compliance date, the first 24-month block would commence on March 1, 2015, and end on February 28, 2017, with the next 24-month block averaging period commencing on March 1, 2017. We believe the 24-month averaging period is reasonable to account for the fact that units needed to address reliability issues (e.g., natural gas curtailment periods) will be called to service sporadically. A 24-month averaging period provides flexibility to ensure that these units can run if there are large periods when natural gas is unavailable. As explained above, the data shows that most of these units operate for less than 8 percent of the time, and in fact it is usually less than 5 percent. Therefore, when considering whether these units would be able to perform stack testing, in many cases this will be for units that in fact operate significantly less than 8 percent of the time. In these cases, the EPA does not want to require the units to operate more just for the purpose of running a stack test resulting in additional pollution and cost. With projections for rising oil prices relative to natural gas prices, we expect this trend to continue. Liquid oil-fired EGUs subject to this subcategory would be required to conduct the same initial and periodic tune-up as all other affected units, but would have no other emission limit or work practice requirements.

Although the EPA believes that the ability to burn oil up to 8 percent of the time should address concerns about units that may need to operate using oil during gas curtailments. The EPA recognizes that if there were a period where gas use was more severely limited, such units might need the flexibility to operate for more than 8 percent in one year and less in the next, which is why we are providing the 2-year period; however based on the data we do not think EGUs in this subcategory will exceed even the 5 percent capacity factor that the data indicate is the average level for these sources.

4. Non-Continental Units

Comment: Commenters from affected island EGUs requested that non-continental EGUs be subcategorized from continental EGUs based on their lack of access to natural gas. The commenters urged the EPA to include a "non-continental liquid oil" subcategory in the final rule. According to the commenters, establishing a subcategory for non-continental units is consistent with the approach the EPA has taken in past rulemakings, including the final Industrial Boiler NESHAP. Non-continental EGUs have little or no access to natural gas, minimal control over the quality of available fuel, and disproportionately high operational and maintenance costs. All oil-fired EGUs operating in Hawaii, Guam, and Puerto Rico combust residual fuel oil exclusively and all are limited by the crude slates of their fuel suppliers. Island utilities can contract with suppliers for certain fuel specifications, such as sulfur content, pour point, flash point, API gravity and viscosity, which the refiners are able to meet primarily by blending and some sulfur removal during the refining process. However, the commenters state that the suppliers do not and cannot economically control for metal content. The crude slate feeding the refinery determines the HAP metal content of the residual oil produced according to the commenters. Because island utilities are dependent on local sources of fuel, they are equally limited by these factors.

Two commenters believe that the separate non-continental subcategory should be expanded to include continental areas that are not interconnected with other utilities and have limited compliance options due to remote locations (*e.g.*, Alaska).

Response: The EPA agrees that the unique considerations faced by non-continental EGUs warrant a separate subcategory for these units and the data show that the difference in location causes a difference in emissions apparently due to the fuel that is available for such units; thus, the Agency has included such a subcategory in the final rule. At proposal, the EPA did not have all of the data from liquid oil-fired units in non-continental areas (*e.g.*, Guam, Puerto Rico) and solicited comment on whether a subcategory should be established, based on the data to be received, for non-continental oil-fired EGUs. The EPA has now received these late data and, based on those data, is finalizing a non-continental subcategory for liquid oil-fired EGUs in Guam, Hawaii, Puerto Rico, and the U.S. Virgin Islands. The EPA is not aware of

[320] Units that co-fire oil and natural gas where the oil combustion comprises 10 percent or less of the capacity factor are natural gas-fired EGUs that are not subject to this final rule.

any liquid oil-fired EGUs in any of the other U.S. territories that meet the CAA section 112(a)(8) definition but, if there are such units, they would also be part of the non-continental subcategory.

The EPA agrees that the unique considerations faced by non-continental refineries, including a limited ability to obtain alternative fuels that lead to different emissions characteristics, warrant a separate subcategory for these EGUs. The EPA believes that units in this subcategory will comply through the use of cleaner oils or, for PM, through the installation of an ESP. The EPA finds no merit in the comment that Alaska should be included in this non-continental subcategory because utilities in Alaska are not faced with the same access issues affecting island-based facilities.

C. Surrogacy

1. Filterable PM vs. Total PM

Comment: Numerous commenters strongly objected to the use of total PM as the surrogate standard for non-mercury HAP metals. They argued that filterable PM is a better surrogate, especially given EPA's intent to use a PM CEMS for continuous compliance demonstration. Other commenters argued that we should not use a surrogate and instead should require direct compliance with a non-mercury HAP metals standard.

Response: We have decided to use a filterable PM limit for the PM surrogate emission limit in the final rule.

Although the objective of the emission limits we are establishing is to reduce the risks associated with HAP emissions, the limits are based in part upon the demonstrated capabilities of control technologies which are installed on existing sources. Except for Hg, the best PM controls provide the best controls of metal emissions. Emissions measurements of either filterable particulate, total particulate, individual metals, or total metals provide comparable indications that the best level of control is achieved. We can find no significant difference in the emissions that would be achieved by using any one of these emissions measurements.

We re-assessed the relationships between individual metal emissions, filterable PM emissions, total PM emissions, and total $PM_{2.5}$ emissions based on the test results provided through part III of the 2010 ICR. We compared the measured emissions of metals and PM with the uncontrolled emissions estimates and found that control of PM was indicative of the control of metals emissions. In addition, we compared the correlations associated with non-mercury HAP metal emissions and the three forms of PM and found that no specific particulate form provided a consistently superior indicator of better metals control. Although control of filterable PM provided the best indicator of performance for control of some HAP metals, control of total particulate or total $PM_{2.5}$ was nearly as good as an indicator. For control of other HAP metals, total PM measurement provided the best indicator of control performance because it included the vapor-phase metal HAP, although, measurement of the control of filterable particulate was nearly as good an indicator. In addition, certain data analyzed by our Office of Research and Development indicate that a vapor-phase metal, such as Se, can be present as an acid gas and reduced significantly using acid gas technologies (wet and dry scrubbing). Given that the rule also provides for acid gas control monitoring, and the general equivalency of the different indicators, we have concluded that use of a filterable PM limit as the PM surrogate emission limit is appropriate.

2. Moisture Content of Oil

Comment: A number of commenters stated that studies suggest that chloride in fuel oil can result from contamination during transportation and processing of crude oils and then be emitted as HCl during combustion. For example, the commenters asserted that the chloride contamination of crude oils can occur as a result of the ballasting of tanker ships with seawater. However, the Oil Pollution Act of 1990 requires all new oil tankers to be double hulled and establishes a phase out schedule (by the middle of the decade) for existing single hulled tankers with un-segregated ballasts. Because of the role of seawater contamination in introducing contaminants into the oil, the commenters suggest that the EPA set a percent water content limit for fuel oil at a level of 1.0 percent, rather than setting HCl and HF emissions limits. This would encourage handling and transport practices to limit salt water contamination. One commenter recommended a standard of 1.0 percent water because several of the lowest HCl and HF emitting units currently require percent water (or water and sediment) specifications between 0.5 percent and 1.0 percent.

Response: The EPA is providing the alternative compliance assurance approaches in the final rule for liquid oil-fired EGUs of demonstrating compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

The EPA is not aware of any FGD systems installed on oil-fired EGUs. Thus, it is only the quality of the oil, and the level of HAP constituents contained therein, that can be relied upon for ensuring compliance.

In the proposal preamble, we stated:

> We believe that chlorine may not be a compound generally expected to be present in oil. The ICR data that we have received suggests that in at least some oil, it is in fact present. EPA requests comment on whether chlorine would be expected to be a contaminant in oil and if not, why it is appearing in the ICR data. To the extent it would not be expected, we are taking comment on the appropriateness of an HCl limit. *See* 76 FR 25045.

Commenters refer to certain studies that provide a plausible reason for the chloride/fluoride contamination of fuel oils. We found this reason persuasive and accordingly are providing alternative compliance approaches in the final rule to demonstrate compliance with the acid gas HAP standards. Specifically, sources can demonstrate compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

D. Area Sources

Comment: Numerous comments were received both in support of and in opposition to the establishment of generally available control technology (GACT) standards for area source EGUs.

Several commenters in opposition to area source standards stated that the EPA properly established emissions limitations based upon the performance of all EGUs, rather than distinguishing between major sources and area sources. The commenters believe that Congress did not intend the EPA to distinguish between "major source" EGUs and "area source" EGUs in determining whether and how to regulate EGUs under CAA section 112. These commenters indicated that differentiating major source and area source EGUs for purposes of setting emissions standards is inappropriate in light of the 2000 Finding regarding the threat posed by the absence of regulation of HAP emissions from EGUs. The 2000 Finding was based upon studies whose conclusions regarding the impacts from EGU emissions did not depend upon any relevant distinction between major source and area source EGUs. The commenters note that segregating "major source" and "area source" EGUs

would have the perverse effect of eliminating some of the best performing sources from the MACT pool of sources that constitute the "best performing" 12 percent. Many of the best performing sources have employed control technology that brings their emissions below the major source threshold, despite the fact that they are larger units. As a result, the commenters believe that if the EPA created standards for "major source" EGUs based only upon those units, the MACT standards for "major source" EGUs would be less stringent for each of the pollutants than proposed in this Rule. At the same time, the less polluting sources, the "area source" EGUs, could face limits more stringent than those proposed in the Rule. Commenters also note that after reviewing the substantial record in this rulemaking, they believe that the EPA has correctly determined that major and area source EGUs greater than 25 MW have similar HAP emissions and use the same control technologies and techniques to reduce HAP emissions. Thus, the commenters asserted that the record demonstrates that there is no technical basis for distinguishing between major and area source EGUs for purposes of establishing HAP emission control standards under CAA section 112(d).

Many commenters in support of an area source designation for EGUs stated that the EPA has promulgated area source limits for many source categories of HAP emissions, including most recently industrial boilers and note that GACT controls have been used successfully in many other EPA MACT rules, including rules for iron & steel foundries, electric arc steelmaking, coatings operations, clay ceramics manufacturing, glass manufacturing, and secondary nonferrous metals manufacturing, in order to reduce costs and regulatory burdens. The commenters state that Congress has given the EPA the ability to subcategorize area sources because of their low HAP emissions and low potential impact on human health and that, contrary to the plain language of CAA section 112 and its legislative history, the EPA made no attempt in the proposed rule to distinguish between major sources and area sources for purposes of listing or setting standards. The commenters indicated that where Congress was concerned about the health impacts of specific pollutants from specific sources, it knew how to specify that MACT limits be promulgated (*e.g.*, CAA section 112(c)(6)). The commenters state that area source rules would lessen the regulatory burden of a CAA section 112 EGU rule on many small entities (arguing that many EGUs owned by small public power entities are area sources) and that as many as 12 percent of the EGU population could qualify as area sources. A number of commenters pointed out that the small entity representatives (SER) on the SBREFA panel suggested that the EPA establish separate emission standards for EGUs located at area sources of HAP and that the standards be based on GACT as allowed under CAA section 112(d)(5). Specifically, the SERs recommended that the EPA establish management practice standards for area source EGUs.

Response: The EPA is not establishing an area vs. major source distinction in the final rule.

The CAA section 112(a)(8) definition of EGU does not distinguish between major and area sources, and we maintain that EGUs are a single source category that contains both major and area sources. The EPA proposed to regulate five subcategories of EGUs without distinguishing between major and area sources for purposes of establishing the standards for the different subcategories. Our approach is wholly consistent with the statutory definition of EGU and reasonable.

Nevertheless, the Agency did examine whether to set separate standards for area source EGUs, because we do not believe that the statute prohibits the Agency from exercising its discretion to establish GACT standards for area sources pursuant to CAA section 112(d)(5) if we determine such standards are appropriate. The EPA is not required, however, to establish GACT standards for area sources, and we believe it may even be unreasonable to do so under the circumstances we identified in the proposed rule as supported by the record of this final rule.

At proposal, we determined that it was not appropriate to establish separate standards for major and area source EGUs, and even if we had exercised our discretion to set separate standards, we would have likely declined to exercise our discretion to set GACT standards for area source EGUs given our appropriate and necessary finding and the fact that a potentially large number of area source EGUs are in fact large well controlled units.

Some commenters note that there could be as many as 12 percent of the total population that could be classified as area sources. We are not sure of the commenters' point in regard to this statement. As to commenters' statements that many of the area sources are municipal utilities, our information shows that many rather large EGUs (*e.g.*, hundreds of MW) are also area sources, and the commenters have not provided any justification for establishing GACT standards for large synthetic area sources.

Commenters did not provide an evaluation of the health and environmental impacts of the area sources and simply presume that the risks from such sources are lower, even though many of the same commenters noted that these smaller EGUs are often located in densely populated areas where populations are more likely to have adverse health effects from the HAP emissions. Furthermore, other commenters, including some industry commenters, noted that the vast majority of these potential area sources meet the criteria due to the installation of emission controls installed to meet other requirements. According to these commenters, these synthetic area sources would likely be able to meet the limits of this rulemaking and imposition of this rule would not appear to result in the installation of additional controls in a number of cases. We do not know if this assertion is correct but we determined approximately 69 coal-fired EGUs will be able to meet the existing source MACT standards with their current control configuration (out of 252 EGUs that reported data for Hg, PM, and HCl in the 2010 ICR).

Commenters also note that the Agency has exercised its discretion in other NESHAP rulemakings to establish area source limits. Although true, the fact that the EPA has established area source limits in some source categories is irrelevant to similar decisions for different source categories. Commenters have not shown that the circumstances applicable to those other source categories are similar to the circumstances identified for major and area source EGUs (*e.g.*, similar controls, similar emission characteristics, large number of synthetic minor area sources). Further, those other source categories are not statutorily defined in a manner that includes both area and major sources. EGUs are the only source category defined in CAA section 112 and, in establishing the definition of an "electric utility steam generating unit" under CAA section 112(a)(8), Congress included in the EGU source category both area and major sources. Thus, it is reasonable to regulate the EGU category in the manner Congress defined the category. Commenters have provided no legal support for the contention that the EPA must regulate area and major sources in the same category in separate rulemakings, and the EPA has in fact regulated both major and area sources in

the same rulemaking even absent a statutory definition that includes both major and area sources. (*See* National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants; 75 FR 54970; September 9, 2010.)

The EPA considered the totality of the circumstances when determining whether to set separate area and major source standards for EGUs and also considered whether it would be reasonable to establish GACT standards for areas sources. We reasonably considered whether emissions characteristics of major and area sources are different when determining whether to establish GACT standards, notwithstanding commenters' assertion that such consideration is not correct. That we also consider emission characteristics in subcategorization decisions is of no consequence for area source decisions. Given that the statutory definition of EGUs contains both major and area sources, it was reasonable to evaluate whether there were sufficient differences between area and major sources when deciding whether to exercise our discretion to set separate area and major source standards.

In addition, we find commenter's point concerning CAA section 112(c)(6) odd because EGUs emit several of the CAA section 112(c)(6) HAP (*e.g.*, lead, Hg). Although EGUs were exempted from that provision, the fact that they emit some of the HAP called out for MACT control supports our decision to not establish GACT standards for any EGUs. CAA section 112(d)(5) leaves it to the Agency's discretion to determine whether GACT standards should be established for area sources, and the statute does not require GACT standards or even indicate that such standards are to be the default regulatory approach for area sources. *See* 76 FR 25021. Instead, the statute provides the Agency with discretion and we have exercised it reasonably in this case.

Commenters indicate that many EGUs owned by small entities are potential area sources. However, commenters fail to note that there are also EGUs owned by small entities that are not potential area sources, and, thus, would not accrue any "lessened regulatory burden" benefit from a decision by the EPA to establish area source standards.

Some commenters state that the EPA's mere assertion that there would be no difference between GACT and MACT to justify an area source finding does not provide sufficient documentation for the decision. But EPA did not say there would be no difference between MACT and GACT. Instead, it stated that it would be difficult to make a distinction given the similarities between the EGUs and major and area source facilities. Specifically, as noted by other commenters, and observable by a review of the MACT Floor Analysis spreadsheets, potential area sources range in size from units near the CAA section 112(a)(8) defined lower size limit to units of hundreds of megawatts. Further, these larger area source units are, for the most part, controlled with the full suite of emission control technologies available (*e.g.*, fabric filters, scrubbers).

In addition, the data that were available in the docket for the proposed rule show that there is little difference between major and area source EGUs individually, and that generally the driver for whether a utility facility is a major or area source depends on the number of EGUs located at a facility (almost exclusively one or two EGUs located at area sources), not on any inherent difference between the EGUs themselves. *See* "Evaluation of Area Source EGUs" TSD, Docket EPA–HQ–OAR–2009–0234. In fact there are a number of EGUs that are quite large that are area sources and others that are small that are major sources. *Id.* This is the case because the acid gas HAP emissions are what drive EGUs to have HAP emissions exceeding the major source threshold. With a few exceptions, the EGUs located at area sources have FGD or other acid gas controls that reduce the acid gas HAP to area source levels. *Id.* Thus, the majority of sources that currently qualify as area sources were, in fact, major sources prior to installing controls. The exceptions are those units that would likely be able to achieve the MACT level of control for acid gas with minimal use of DSI at a reasonable cost. *Id.*

In addition, the data show that a number of area sources for which we have data are high emitters of Hg and non-Hg metal HAP. *Id.* Pursuant to our appropriate and necessary finding, these HAP pose a significant threat to human health. Thus, even were we to distinguish between major and area sources, which we do not believe is appropriate given the similarities between such sources, we would still decline to set GACT standards, and as such we maintain that MACT standards are appropriate. Moreover, for acid gas HAP, as discussed above, the data indicate that the level of control would likely be the same even if we did establish GACT standards under CAA section 112(d)(5).

We fully evaluated the nature of EGUs, and we do not see a basis on which to distinguish these sources for purposes of setting standards. Thus, we maintain that we reasonably exercised the discretion afforded the Agency under the statute and declined to set separate standards for area source EGUs.

E. Health-Based Emission Limits

Comment: Many commenters noted that in the proposed rule the EPA considered whether it was appropriate to exercise its discretionary authority to establish health-based emission limits (HBEL) under CAA section 112(d)(4) for HCl and other acid gases and proposed not to adopt such limits, citing, among other things, information gaps regarding facility-specific emissions of acid gases, co-located sources of acid gases and their cumulative impacts, potential environmental impacts of acid gases, and the significant co-benefits estimated from the adoption of the conventional MACT standard. Comments were received both supporting this position and refuting it. Several commenters suggested legal, regulatory and scientific reasons for why HBEL for HCl might be appropriate for this MACT standard. With respect to legal concerns, some commenters indicated that CAA section 112(d)(4) establishes a mechanism for the EPA to exclude facilities from certain pollution control regulations and circumstances when these facilities can demonstrate that emissions do not pose a health risk. Commenters cited a Senate Report that influenced development of CAA section 112(d)(4), where Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." (Footnote: S. Rep. No. 101–128 (1990) at 171.) Commenters also cited regulatory precedent for addressing HCl as a threshold pollutant, including the Hazardous Waste Combustors and the Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills NESHAP. Commenters requested that the EPA incorporate the flexibility afforded by CAA section 112(d)(4) and allow sources reasonable means for demonstrating that their respective emissions do not warrant further control. The commenters also cited the 2004 vacated Boiler MACT as precedent for HBEL for HCl. The commenters contended that the EPA failed to explain why the health-based emissions limitations it established in the 2004 Boiler MACT and the justification provided for those limitations could not be used in this case. The commenters also cited a 2006

court briefing where the EPA vigorously defended the HBEL included in the 2004 Boiler rule when it was challenged in the D.C. Circuit (Final Brief For Respondent U.S. Environmental Protection Agency, D.C. Cir. Case No. 04–1385 (Dec. 4, 2006) at 59–65, 69).

Other commenters stated that on August 6, 2010, the EPA adopted a NESHAP for Portland Cement plants that specifically rejected adoption of risk-based exemptions or HBEL for HCl and manganese (Mn). These commenters argue there are no differences sufficient to warrant a reversal of that decision in the EGU MACT standard. The commenters raised concerns that health risk information cited by the EPA for HCl, HF, and hydrogen cyanide (HCN) does not establish "an ample margin of safety" and, therefore, no health threshold should be established. The commenters believe risk-based exemptions at levels less stringent than the MACT floor are prone to lawsuits that could potentially further delay implementation of the EGU MACT.

Some commenters disagreed with using a hazard quotient (HQ) approach to establish a risk-based standard because the HQ would not account for potential toxicological interactions. The commenter noted that an HQ approach incorrectly assumes the different acid gases affect health through the same health endpoint, rather than assuming that the gases interact in an additive fashion. This commenter suggested that a hazard index approach, as described in the EPA's "Guideline for the Health Risk Assessment of Chemical Mixtures," would be more appropriate.

Some commenters dispute that emissions from other EGUs or source categories should be considered when developing an HBEL and they argued that Congress expected the EPA to consider the effect of co-located facilities during the CAA section 112(f) residual risk program instead of under CAA section 112(d). Commenters added that there is no prior EPA precedent for considering co-located facilities from a different source category during the same CAA section 112 rulemaking.

Several commenters disputed the EPA's consideration of non-HAP collateral emissions reductions in setting MACT standards. They contended that the EPA's sole support for its "collateral benefits" theory is legislative history—the Senate Report that accompanied Senate Bill 1630 in 1989 and noted that the D.C. Circuit rejected this use of this theory since the Senate Report referred to an earlier version of the statute that was ultimately not enacted. Instead commenters suggested that other components of the CAA, such as the National Ambient Air Quality Standards (NAAQS), are more appropriate avenues for mitigating emissions of criteria pollutants.

Several other commenters suggested it is impossible to assess an established health threshold for HCl such that a CAA section 112(d)(4) standard could be set without evaluating the collateral benefits of a MACT standard. And, as described in the recently finalized cement kiln MACT rule, setting technology-based standards for HCl will result in significant reductions in the emissions of other pollutants, including SO_2, Hg, and PM. The commenter added that these reductions will provide enormous health and environmental benefits, which would not be experienced if CAA section 112(d)(4) standards had been finalized. These commenters contended that HCl and other dangerous acid gases produced by EGUs pose substantial risks to industrial workers, as well as surrounding communities, and must be limited by the strict conventional MACT standards.

Several commenters indicated that the current economic climate requires the EPA to balance economic and environmental interests and indicated that HBEL would help target investments into solving true health threats where limits are no more or less stringent than needed to protect public health. Many commenters provided estimates of compliance cost savings if an HBEL is included in this final rule. Some commenters stressed the importance of an HBEL for small entities affected by the regulations. Several other commenters suggested that the EPA should estimate the costs and environmental effects of the HBEL option compared to a conventional MACT standard in order to make an informed decision on the adoption of HBEL.

Response: After considering the comments received, the EPA has decided not to adopt an emissions standard based on its authority under CAA section 112(d)(4) for all the reasons set forth in the proposed rule.

The EPA notes that the Agency's authority under CAA section 112(d)(4) is discretionary. That provision states that the EPA "may" consider establishing health thresholds when setting emissions standards under CAA section 112(d). By the use of the term "may," Congress clearly intended to allow the EPA to decide not to consider a health threshold even for pollutants which have an established threshold. As explained in the preamble to the proposed rule, it is appropriate for the EPA to consider relevant factors when deciding whether to exercise its discretion under CAA section 112(d)(4), and, notwithstanding commenters' assertions to the contrary, the considerations we include in our analysis are reasonable. The EPA has considered the public comments received and is not adopting an emissions standard under CAA section 112(d)(4) for the reasons set forth in the proposed rule and explained below. We note that this action is consistent with EPA's recent decisions not to develop standards under CAA section 112(d)(4) for the Industrial, Commercial and Institutional Boilers and Process Heaters and the Portland Cement source categories.

As explained in the preamble to the proposed rule, the EPA continues to believe that the potential cumulative public health and environmental effects of all acid gas HAP emissions, not just HCl emissions, from EGUs and other acid gas sources located near EGUs supports the Agency's decision not to exercise its discretion under CAA section 112(d)(4). Additional data for all acid gas emissions were not provided during the comment period, and the data already in hand regarding these emissions are not sufficient to support the development of emissions standards for EGUs under CAA section 112(d) that take into account the health threshold for acid gas HAP, particularly given that the Act requires the EPA's consideration of health thresholds under CAA section 112(d)(4) to protect public health with an ample margin of safety. We note here that EPA agrees with the commenter who pointed out that a better way to evaluate the potential health impact interactions of all acid gases would be to use the approach in EPA's "Guideline for the Health Risk Assessment of Chemical Mixtures" rather than a simple evaluation of individual HQ values for each acid gas, but we further note that use of such an approach requires a substantially greater knowledge of acid gas emissions than is currently available. We further note that, even if cost were a relevant factor in setting standards under CAA section 112(d)(4), since the data are not available that would allow us to develop an acid gas HBEL appropriate to protect public health with an ample margin of safety, we cannot determine whether such standards would have any cost savings associated with them or not. In addition, the concerns expressed by the EPA in the proposal regarding the potential environmental impacts and the cumulative impacts of acid gases on public health were not assuaged by the

comments received because no significant data regarding these impacts were received.

The EPA also received comments recommending not only that the EPA establish emissions standards for acid gases pursuant to CAA section 112(d)(4), but that it do so by excluding specific facilities from complying with emissions limits if the facility demonstrates that its emissions do not pose a health risk. The EPA does not believe that a plain reading of the statute supports the establishment of such an approach. Although CAA section 112(d)(4) authorizes the EPA to consider the level of the health threshold for pollutants which have an established threshold, that threshold may be considered "when establishing emissions standards under [CAA section 112(d)]." Therefore, the EPA must still establish emissions standards under CAA section 112(d) even if it chooses to exercise its discretion to consider an established health threshold. A source-by-source standard is not mandated as some commenters seem to imply, and we are unsure how we could reasonably implement such an approach even if we determined such an approach was legally available. For these reasons alone, we concluded it was not appropriate to exercise our discretion to establish section 112(d)(4) standards for acid gas HAP emissions.

In addition, as explained in the preamble to the proposed rule, the EPA also considered the co-benefits of setting a conventional MACT standard for HCl. The EPA considered the comments received on this issue and continues to believe that the estimated co-benefits are significant and provide an additional basis for the Administrator to conclude that it is not appropriate to exercise her discretion under CAA section 112(d)(4). The EPA disagrees with the commenters who stated that it is not appropriate to consider non-HAP benefits in deciding whether to invoke CAA section 112(d)(4). Although MACT standards may directly regulate only HAP and not criteria pollutants, Congress did recognize, in the legislative history to CAA section 112(d)(4), that MACT standards would have the collateral benefit of controlling criteria pollutants as well and viewed this as an important benefit of the air toxics program. *See* S. Rep. No. 101–228, 101st Cong. 1st sess. at 172. The EPA consequently does not accept the argument that it cannot consider reductions of criteria pollutants in determining whether to take or not take certain discretionary actions, such as whether to adopt an HBEL under CAA section 112(d)(4). There appears to be no valid reason that, in situations where the EPA has discretion in what type of standard to adopt, the EPA must ignore controls which further the health and environmental outcomes at which CAA section 112(d) is fundamentally aimed because such controls not only reduce HAP emissions but emissions of other air pollutants as well. Thus, the issue being addressed is not whether to regulate non-HAP under CAA section 112(d) or whether to consider other air quality benefits in setting CAA section 112(d)(2) standards—neither of which the EPA is doing—but rather whether EPA may exercise its discretion to regulate certain HAP based on the MACT approach and consider collateral health and environmental benefits when choosing whether to exercise that discretion. The EPA believes there is no legal principle that precludes it from doing so and commenters have not provided one.

F. Compliance Date and Reliability Issues

Comment: Multiple commenters asked that the compliance date be clearly stated as soon as possible, as well as that guidance be provided for utilities unable to comply with the stated timelines, to allow time for utilities to prepare for compliance. Commenters also asked that any decisions or policies on extensions be published in a rulemaking. In addition, commenters requested that the EPA establish, streamline, and simplify the process of applying for the 1-year extension under CAA section 112(i)(3).

Multiple commenters offered suggestions on methods for allowing more time for compliance, including EPA's authority under CAA section 112(n)(1)(A); state authority under CAA section 112(i)(3); Presidential authority under CAA section 112(i)(4); categorical extensions for publicly-owned or governmental facilities according to EO 13132, 13563, and UMRA of 1995; state-designed programs under the delegation provisions of CAA section 112; various Consent Decrees; Administrative Orders of Consent (AOCs); temporary waiver mechanisms; and adoption of MACT compliance schedules through minor permit modifications of a source's Title V federal operating permits. Absent such considerations for additional compliance time, many commenters suggested that the reliability of the nation's electric grid would be jeopardized as utility companies were forced to retire EGUs because they could not install the needed controls in the requisite time.

Compliance times requested by commenters ranged from 1 additional year (4 years total) to 6 additional years (9 years total). Multiple commenters requested that a utility be required to demonstrate good faith progress toward compliance to get any extension. Some commenters suggested that the EPA require utilities to submit a notice concerning which EGUs will be retrofitted or retired within 1 year of the effective date; that the compliance date align with the Power Year used by RTOs; and that the EPA clarify that retirement and any clean replacement power that complies with the NESHAP rule, including off-site combined heat and power and waste heat recovery, can be deemed "controls" under the CAA.

Commenters noted the specific situations related to small entities and their inability to compete with the larger, investor-owned utilities for financing and engineering and technical labor as well as the different process they need to follow for capital improvements. Multiple commenters asked that the EPA consider other simultaneous rulemakings (*e.g.*, Cooling Water Intake Structures; Coal Combustion Residuals; CSAPR, etc.) and extend the compliance period. Many commenters noted these other requirements and suggested that installation of the necessary controls could not be completed within the compliance period allowed under CAA section 112, even if a fourth year were to be granted by the permitting authority, citing examples of the times necessary for installation of various pieces of control equipment or replacement power.

Some commenters pointed to existing state programs (*e.g.*, Colorado, Oregon, Washington) and indicated that if states can demonstrate that overall emissions reductions would be equivalent or greater than those that would be achieved by the proposed rule, the EPA should delegate the CAA section 112 program to these states, even if the state emissions reductions would not necessarily occur on the same schedule (many state programs call for retirement of EGUs in years beyond the CAA section 112 compliance date). The commenters did not want the promulgation of the final rule to undermine the significant amount of work that may have been invested in creating state-specific programs to curb emissions within a reasonable timeframe. The commenters seek to make use of temporal flexibility, authorized under CAA section 112(i)(3), in obtaining delegation of the final rule to preserve the hard-negotiated comprehensive state-specific programs designed to yield greater emission reductions than the MATS alone.

Other commenters requested that no additional time be granted for compliance. These commenters reference a number of reports (*e.g.*, by the URS Corporation, by M.J. Bradley & Associates and the Analysis Group, and by the Bipartisan Policy Center) to indicate that not only is technology readily available, but that the technology can typically be installed in less than 2 years and that the electric industry is well-positioned to comply with the EPA's proposed air regulations without threatening electric system reliability. Commenters assert that, if electric system reliability were to be threatened in local areas as a result of the rule, the EPA has the statutory authority to grant, on a case-by-case basis, extensions of time to complete the installation of pollution control systems. One commenter stated that no additional controls would need to be installed in many cases and any coal unit should be able to comply with all of the standards. Another commenter noted that utilities that failed to plan ahead "should not be permitted to use their own inaction to justify more time." Commenters noted that several major utility companies have anticipated the EPA's rules and are already taking action to ensure a reliable supply of electricity in their service territory and beyond. Other commenters agree that there is significant excess generation capacity in the country and reliability will not be threatened by the rule. According to one commenter, companies are already preparing for a 2015 compliance date, factoring in the capital expenditures required to comply and delays would undermine decisions that have already been made. Commenters cite, for example, recent electricity forward capacity market auctions in the PJM market for the period of 2014 and 2015 that indicate that the capacity markets cleared with electricity reserve margins of 20 percent; this is in excess of the default reliability targets used by the North American Electric Reliability Corporation (NERC) for the year 2015. One commenter quoted NERC, stating that NERC does not see impacts from proposed climate legislation or anticipated EPA regulation as a reliability concern. Another commenter noted that the Building and Construction Division of the AFL–CIO has stated that there is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology installation. In fact, according to the commenter, given the high levels of unemployment in the construction sector, these jobs are much needed.

A number of commenters expressed concern that the time frame for compliance with a regulation under CAA section 112(d) was too short for this industry and would result in compromising the reliability of electricity supply. Commenters asserted that reliability would be compromised in several ways: (1) EGUs might have to temporarily close if the owner or operator is unable to install controls on the unit within the 3-year time frame or 3 years plus one; (2) the timing of outages to install controls will cause short term closures that could threaten grid stability; (3) owner/operators may shut down EGUs rather than invest in retrofits to keep them running and that these closures may cause a loss of critical generation; and (4) the construction of replacement generation or implementation of other measures to address reliability concerns due to plant retirements could take longer than 3 years, and that units slated for closure may be necessary beyond the 3-year compliance period but will be unable to run because they have not installed the necessary controls.

Response: Clean Air Act section 112 specifies the dates by which affected sources must comply with this rule. New or reconstructed units must be in compliance immediately upon startup or the effective date of this rule, whichever is later. Existing sources may be provided up to 3 years after the effective date to comply with the final rule; if an existing source is unable to comply within 3 years, a permitting authority has the ability to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls.

As is explained earlier in this preamble, the 3-year compliance window is based on the date that is 60 days after publication of this rule in the **Federal Register**. Because publication doesn't occur until several weeks after the rule is signed by the Administrator, the earliest required date for compliance would be sometime in March 2015. Because the last stage of control installations usually needs to occur when the unit is off-line and because scheduled outages are usually scheduled for the spring or fall months when peak electric demand is lower, this additional time is significant as it provides companies an additional outage period, the spring of 2015, to install controls.

The EPA has considered the concerns raised by commenters and has concluded that given the flexibilities further detailed in this section, the requirements of the final rule for existing sources can be met by most sources without adversely impacting electric reliability. In particular, EPA believes that the flexibility of permitting authorities to allow a fourth year for compliance should be available in a broad range of situations (as discussed below), and that this flexibility addresses many of the concerns that have been raised. Furthermore as indicated below, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability.

The EPA considered the impact that potential retirements in response to this rule will have on resource adequacy in order to gauge the rule's impact on reliability. In considering these impacts, the EPA considered both the analysis it has conducted as well as analyses conducted by a number of other groups. The EPA's analysis shows that the expected retirements of coal-fueled units as a result of this final rule (4.7 GW) are fewer than was estimated at proposal and much fewer than some have predicted.[321] The net capacity reductions projected by the EPA make up less than one-half of one percent of the total generating capacity in the U.S. and about one and one-half percent of U.S. coal capacity. Because concerns have been raised that the use of DSI may not be as prevalent as the Agency has predicted and because this could lead to more coal retirements, the Agency also performed a sensitivity analysis in which fewer DSI systems and more scrubber systems were installed. In that sensitivity, we see approximately 1 more GW of retirements. This small change would have only a very small potential impact on resource adequacy. When considering the impact that one specific action has on power plant retirements, it is important to understand that the economics that drive retirements are based on multiple factors including: expected demand for electricity, the cost of alternative generation, and the cost of continuing to generate using an existing unit. The EPA's analysis shows that the lower cost of alternative fuels, particularly natural gas, as well as reductions in demand, will have a greater impact on the

[321] The EPA's analysis also identifies a small amount of capacity loss (less than 0.7 GW) due to derating of certain units, as well as partially offsetting reductions in non-coal retirements in comparison with the base case. The net estimated reduction in capacity, in comparison with the base case, is estimated at less than 5 GW.

number of projected retirements than will the impact of this final rule.

The EPA's assessment looked at the capacity reserve margins in each of 32 subregions in the continental U.S. Demand forecasts used were based on EIA projected demand growth. The analysis shows that with the addition of very little new capacity, average reserve margins are significantly higher than required. The NERC assumes a default reserve margin of 15 percent while the average capacity margin seen after implementation of the policy is nearly 25 percent. Although such an analysis does not address the potential for more localized reliability concerns associated with transmission constraints or the provision of location-specific ancillary services (such as voltage support and black start service), the number of retirements projected suggests that the magnitude of any local reliability concerns should be manageable with existing tools and processes.

Several outside analyses have reached conclusions consistent with EPA's analysis. The DOE, in December 2011, published a report that looked at resource adequacy in the bulk power system when faced with a stress test which was a regulatory scenario far more stringent than EPA's regulations.[322] For this stress test, in addition to CSAPR and MATS requirements, each uncontrolled electric generator is required to install both a wet FGD system and a fabric filter to reduce air toxics emissions. If such installations are not economically justified, this scenario assumes that the plant must retire by 2015. In reality, as discussed previously, power plant owners will have multiple other technology options to comply with the regulations—options that typically cost less than installations of FGDs and fabric filters. The analysis finds that target reserve margins can be met in all regions, even under these stringent assumptions. Moreover, in every region but one (TRE), no additional new capacity is needed. In TRE, the analysis finds that less than 1 GW of new natural gas capacity would be needed by 2015 beyond the additions already projected to occur in the Reference Case. This analysis also finds that the total amount of new capacity that would be added by 2015 is less than the amount that is already under development.

In June 2011, the Bipartisan Policy Center issued a report analyzing potential collective impacts of EPA's pending power sector rules and concluding that "scenarios in which electric system reliability is broadly affected are unlikely to occur." [323]

In August 2011, PJM Interconnection—the Regional Transmission Operator (RTO) responsible for planning and reliable operation of the bulk power system serving all or portions of 13 states in the Mid-Atlantic and Midwestern regions—issued a report analyzing the impacts of the CSAPR and the proposed MATS rule.[324] Although PJM's analysis assumes substantially more retirements than EPA projects, it nevertheless concludes that resource adequacy is not threatened in the PJM region. This is particularly significant, given that the PJM region is one of the largest and most heavily dependent on coal-fueled generation in the country. The PJM analysis notes, as EPA has acknowledged, that even where there is adequate generation capacity on a regional basis, localized reliability issues may emerge in connection with retirements that may need to be addressed.

The EPA has reviewed industry and NERC studies suggesting, contrary to the EPA's and these other groups' analyses, that EPA rules affecting the power sector (including this final rule, the CSAPR, EPA's proposed rule addressing power plant cooling water intake systems under section 316(b) of the Clean Water Act (CWA), and EPA's proposed rule addressing coal combustion residuals under the Resource Conservation and Recovery Act) will result in substantial power plant retirements. Some of these studies predict that such levels of retirements will have adverse effects on electric reliability in some regions of the country. Although the specifics of these analyses differ, in general they share a number of serious flaws in common that call their conclusions into question.

First, most of these studies make assumptions about the requirements of the EPA rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals or final rules. For example, a large proportion of the retirements projected by several of these studies is attributable to their inaccurate assumption that EPA's cooling water intake rule under CWA section 316(b) would require all or virtually all existing power plants to install cooling towers. In one study, the reliability effects reported are based on inaccurate assumptions that all existing EGUs with a capacity utilization factor of less than 35 percent would close, and that all in-scope electric generators would be required to install cooling towers within 5 years, whereas the not-selected options with closed cycle cooling in EPA's proposal envisioned that permit authorities could exercise discretion to allow facilities 10 to 15 years' time to comply. In most cases, these analyses were performed before the CWA section 316(b) rule or the MATS rule were even proposed; even analyses subsequent to the CWA section 316(b) proposal continue to inaccurately portray EPA's proposed approach.

Second, in reporting the number of retirements, many analyses fail to differentiate between plant retirements attributable to the EPA rules and retirements of older, smaller, and less efficient plants that are already scheduled for retirement because owners have made business decisions, based in significant part on market conditions, not to continue operating them.

Third, most of these analyses fail to account for the broad range of responses available to address electric reliability concerns associated with power plant retirements, including upgrades to the transmission system, construction of new generation, and implementation of demand-side measures. These measures are discussed at greater length below.

As a preliminary matter, none of these situations, either alone or in combination, will necessarily lead to an electric reliability problem. There is excess generating capacity in the U.S. today and in most cases an EGU that closes, either temporarily until it comes into compliance or permanently, will not cause a reliability problem. As explained above, our modeling of the impact of this final rule at the regional level projects retirements of less than one percent of nationwide generating capacity and confirms that there will continue to be adequate capacity in all 32 subregions of the country as sources comply with the rule.[325] This analysis shows that significantly less capacity will close in response to the final rule than might have under the proposal. Moreover, the regional modeling of retirements demonstrates that plants that close in response to this rule are spread out across the country rather than clustered in one area.

Outside analyses have identified many of the same flaws in studies

[322] U.S. Department of Energy, December 2011, "Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations."

[323] Bipartisan Policy Center, June 2011, "Environmental Regulation and Electric System Reliability."

[324] PJM Interconnection, August 26, 2011, " Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants."

[325] *See* Technical Support Document on Resource Adequacy in this Docket.

projecting large-scale retirements as a result of EPA's power sector rules. For example, on August 8, 2011, the Congressional Research Service (CRS) [326] issued a report concluded that studies that assert that EPA rules will cause reliability problems, often make assumptions about the requirements of the rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals. The CRS further noted that EPA's rules will primarily affect units that are more than 40-years old, that have not yet installed state-of-the-art pollution controls, and that are inefficient. Many of these plants are being replaced by combined cycle natural gas plants, driven more my lower gas prices than by EPA's regulations. The June 2011 Bipartisan Policy Center report referenced above likewise highlighted many of these same shortcomings in the studies in question.[327]

Although we do not expect to see any regional reliability problems, we acknowledge that there could be localized reliability issues in some areas—due to transmission constraints or location-specific ancillary services provided by retiring generation—if utilities and other entities with responsibility for maintaining electric reliability do not take actions to mitigate such issues in a timely fashion. There are many potential actions that could be taken to address this problem and multiple safeguards to assure a reliable electricity supply.

First, utilities can help to assure reliability through proactive steps in coordination with relevant planning and regulatory authorities. As we said in the proposal, early planning is key. The industry has adequate resources to install the necessary controls and develop the new capacity that may be required within the compliance time provided for in the final rule.[328] Although there are a significant number of controls that need to be installed across the industry, with proper planning, we believe that the compliance schedule established by the CAA can be met. Many companies have begun to do the detailed analysis and engineering and are ahead of others in their compliance strategy. There are already tools in place (such as integrated resource planning, and in some cases, forward auctions for future generating capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as this final rule.

Second, companies that intend to retire EGUs should formally notify their RTO (or comparable planning authority in the case of non-RTO regions), state regulatory agencies, and regional reliability entities as soon as possible of their compliance plans, particularly with regard to any planned unit retirements. As we said before, in most places a closing plant will not be a cause for concern for reliability. The same is true of any outages required for retrofitting of units with controls. To the extent there is concern, however, early notification will provide an opportunity for transmission planners, market participants, and state authorities to develop solutions to avoid a reliability problem. In RTOs with forward capacity markets, owner/operators that do not bid generating capacity that they plan to shut down will provide an advance signal to market participants to take action to assure adequate future capacity. In all regions, early and public notification will allow market participants, planning coordinators and state authorities, as appropriate and in a timely fashion, to bring new generation on line, put demand side resources in place, and/or complete any transmission upgrades needed to circumvent a potential issue. Most RTOs only require 45 to 120 days notification of closure. In combined comments to EPA, 5 RTOs suggested that such notification should be made no later than 12 months after this regulation is final in order to allow a smooth transitioning to action to avoid a reliability problem. The EPA strongly encourages sources to provide notice to the RTOs as early as possible and believes that responsible owner/operators should and will do the early planning for compliance and provide early notification of their compliance plans, especially where such plans include retiring one or more units.

On the supply side, there are a range of options including the development of more centralized power resources (either base-load or peaking) and/or the development of cogeneration or distributed generation. Even with the current large reserve margins, there are companies ready to implement supply-side projects quickly. For instance, in the PJM region, there are over 11,600 MW of capacity that have completed feasibility and impact studies; the units representing this capacity could be on-line by the third quarter of 2014.[329] The EPA notes, as well, that in the 3 years from 2001 to 2003, industry brought over 160 GW of generation on line.[330]

Demand side options include energy efficiency as well as demand response programs. These types of resources can also be developed very quickly. In 2006, PJM had less than 2,000 MWs of capacity in demand side resources. Within 4 years this capacity nearly quadrupled to almost 8,000 MW of capacity.[331] In addition to helping address reliability concerns, reducing demand through mechanisms such as energy efficiency and demand side management practices has many other benefits. It can reduce the cost of compliance and has collateral air quality benefits by reducing emissions in periods where there are peak air quality concerns.

With regard to transmission, recent experience also shows that, in many cases, transmission upgrades to address reliability issues from plant closures can be implemented in less than 3 years. For instance, when Exelon notified PJM of its intention to retire four units,[332] it was determined that transmission upgrades necessary to allow retirement of two units could be made within 6 months of notification, transmission upgrades for the third unit would require slightly over 1 year and transmission upgrades to allow the fourth unit to retire could be made in approximately 18 months.[333]

The CAA allows CAA Title V permitting authorities the discretion to grant extensions to the compliance time of up to one year if needed for installation of controls. *See* CAA section 112(i)(3)(B)). If an existing source is unable, despite best efforts, to comply within 3 years, a permitting authority has the discretion to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls. Id. Permitting authorities should be familiar with the operation of the 1-year

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[326] James E. McCarthy and Claudia Copeland, Congressional Research Service, August 8, 2011, "EPA's Regulation of Coal-Fired Power: Is a 'Train Wreck' Coming?".

[327] Bipartisan Policy Center, June 2011, "Environmental Regulation and Electric System Reliability."

[328] As stated above, EPA has provided the maximum compliance time authorized under CAA section 112(i)(3)(A).

[329] Paul M Sotkiewicz, PJM Interconnection, Presentation at the Bipartisan Policy Commission Workshop Series on Environmental Regulation and Electric System Reliability, Workshop 3: Local, State, Regional and Federal Solutions, January 19, 2011, Washington, DC, *http://www.bipartisanpolicy.org/sites/default/files/Paul%20Sotkiewicz-%20Panel%202_0.pdf*, slide 6.

[330] Form EIA–860 Annual Electric Generator Report, *http://www.eia.gov/cneaf/electricity/page/eia860.html.*

[331] BPC slides cited above—slide 5.

[332] *http://www.exeloncorp.com/Newsroom/pages/pr_20091202_Generation.aspx?k=eddystone.*

[333] Cromby Units 1 and 2 and Eddystone Units 1 and 2—Deactivation Study, Updated September 7, 2010—*http://policyintegrity.org/documents/20100907-cromby-and-eddystone-retirement-study-posting-update.pdf.*

extension provision because EPA has established regulations to implement the provision and the provision applies to all NESHAP. *See* 40 CFR 63.6(i)(4)(A).

We believe that the permitting authorities have the discretion to use this extension authority to address a range of situations in which installation schedules may take more than 3 years including: staggering installations for reliability reasons or other site-specific challenges that may arise related to source-specific construction, permitting, or labor, procurement or resource challenges. Staggered installation allows companies to schedule outages at multiple units so that reliable power can be provided during these outage periods. It can also be helpful for particularly complex retrofits (*e.g.,* when controls for one unit need to be located in an open area needed to construct controls on another unit). The additional 1-year extension would provide an additional two shoulder periods (*i.e.,* seasons flanking annual high-demand periods) to schedule outages, thus enabling owners/operators to gain the full benefit of staggering outages in support of complex installations. The EPA believes that although most units will be able to fully comply within 3 years, the fourth year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. That fourth year should be broadly available to enable a facility owner to install controls within 4 years if the 3-year time frame is inadequate for completing the installation.

As we indicated at proposal, this source category is unique due to the large, complex and interconnected nature of electrical generation, transmission and distribution, and the critical role of the electric grid in the functioning of all aspects of the economy. The grid functions as an interconnected system that supplies electricity to end users on a continuous basis. Safe, reliable operation of the grid requires coordination among actions taken at individual units, including timing of outages for the installation of controls, derating, or deactivation. It was for this reason that we specifically addressed in the proposed rule reasonable interpretations of the phrase "installation of controls" in CAA section 112(i)(3)(B). We determined that it was important to provide Title V permit authorities with information that might be useful if they were asked to authorize a fourth year for specific EGUs.

The EPA took comment on whether the construction of on-site replacement power could be considered the "installation of controls" such that a fourth year would be available while the replacement unit is being completed for a unit that is retiring (*e.g.,* a case when a coal-fueled unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine). After reviewing the comments, EPA believes that it is reasonable for permit authorities to allow the fourth year extension to apply to the installation of replacement power at the site of the facility. The EPA believes that building replacement power constitutes the "installation of controls" at a facility to meet the regulatory requirements.

Commenters were generally supportive of the proposed approach described above, but a number of commenters suggested several additional situations that should be considered as the "installation of controls" such that it would be appropriate for permitting authorities to grant a 1-year extension beyond the 3-year compliance time-frame. In particular, commenters suggested that the 1-year extension should be available for a unit if a company's compliance choice was to retire that unit but doing so within the 3-year time-frame caused reliability problems for any of the following reasons: (1) Generation from the retiring unit is needed to maintain reliability while other units install emission controls; (2) new off-site generation was being built to replace the retiring unit, but the new generation was not scheduled to be operational within the 3-year time-frame and any gap between the time the existing unit retires and the new unit comes on line would cause reliability problems; and (3) transmission upgrades were needed in order to maintain electric reliability after the unit retired but could not be completed within 3 years.

While the ultimate discretion to provide a 1-year extension lies with the permitting authority, EPA believes that all three of these cases may provide reasonable justification for granting the 1-year extension if the permitting authority determines, for example, based on information from the RTO or other planning authority or other entities with relevant expertise, that continued operation of a particular unit slated for retirement for some or all of the additional year is necessary to avoid a serious risk to electric reliability.

In a case where pollution controls are being installed, or onsite replacement power is being constructed to allow for retirement of older, under-controlled generation, a determination that an extra year is necessary for compliance should be relatively straightforward. In order to install controls, companies will have to go through a number of steps fairly early in the process including obtaining necessary building and environmental permits and hiring contractors to perform the construction of the emission controls or replacement power. This should provide sufficient information for a permitting authority to determine that emission controls are being installed or that replacement power is being constructed. Because companies will need to develop this information early in the process and because a determination can easily be made as to whether the schedule will exceed 3 years, the EPA believes that Title V permitting authorities should be able to quickly make determinations as to when extensions are appropriate.

In the three cases related to retirement of a unit without construction of onsite replacement power, additional information is needed. The Title V permitting authority should request that the affected company or companies provide information, including, for example, from the RTO or other planning authority for the relevant region, the state electric regulatory agency, NERC or its regional entities, and/or FERC or the DOE, demonstrating that retirement of a particular unit within the 3-year compliance period would result in a serious risk to electric reliability.

The first two situations involving a retiring unit—where one or more related existing units are upgrading pollution controls or a new unit is being constructed off-site—are similar to the situation we discussed in the proposed rule wherein a retiring unit at a facility runs an additional year while a replacement unit on the same site is constructed. In each of these situations, the retiring unit would be allowed to run so a unit compliant with the rule (either a retrofitted existing unit or a new unit) can come on line. We believe that these situations may, in the appropriate circumstances, constitute ones in which a 1-year extension for the retiring unit is "necessary for the installation of controls." In these two situations, however, we believe that it would be appropriate for the Title V permitting authority to consider reliability concerns as a necessary factor before granting the additional year because continuing operation of the retiring unit is only "necessary" to the extent it is required for reliability. In each of these situations, the permitting authority should determine that the retiring unit is necessary to maintain

reliability until the new unit comes on line or the other existing unit is retrofitted. Title V permitting authorities may determine that multiple retiring units are available to maintain reliability, but unless all the units are necessary to address the issue, it would likely be unreasonable to provide the additional year for all the identified units.

The third hypothetical situation identified above is one in which transmission upgrades are necessary to address a reliability issue resulting from the retirement of a unit in order to comply with this rule, where the upgrade cannot be completed by the 3-year compliance date. In terms of the functionality of the electric grid, this situation has some similarity to those discussed above. Here, it is the completion of the transmission upgrades, rather than bringing another compliant (retrofitted or new) unit on line, that would allow the retiring unit to come into compliance (by retiring) without threatening reliability. The general objective and result is similar: Reductions of the existing unit's HAP emissions (through retirement) while maintaining electric reliability. If such situations develop and the reliability problem has been properly demonstrated, permitting authorities should consider whether an extension under CAA section 112(i)(3)(B) may be provided.

The EPA continues to believe, based on the analysis discussed at the beginning of this section, that most, if not all, units will be able to comply with the requirements of this rule within 3 years. The EPA also believes that making it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in the range of situations described above, addresses many of the other concerns that commenters have raised. The EPA believes that the number of cases in which a unit is reliability critical and in which it is not possible to either install controls on the unit or mitigate the reliability issue through construction of new generation, transmission upgrades, or demand-side measures, within 4 years, is likely to be very small or nonexistent. This view is consistent with statements from commenters explicitly mandated with ensuring grid reliability.

The EPA's authority to provide relief from the requirements of this final rule beyond the fourth year is limited by the statute. If reliability issues do develop, however, the CAA provides mechanisms for sources to come into compliance while maintaining electric reliability. One area where the EPA has some measure of flexibility is with respect to the exercise of its enforcement authorities. The Agency has used such authority in the past to bring sources into compliance with the requirements of the CAA while maintaining electric reliability, although these authorities are not as flexible as suggested by some commenters.

The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly well in advance of the date when a violation may occur. In light of the importance of ensuring electric reliability, however, the Office of Enforcement and Compliance Assurance will separately publish a document that articulates our intended approach with respect to sources that operate in noncompliance with this final rule to address a specific and documented reliability concerns.

That document provides a pathway for reliability critical units (as such units are described in the document) to achieve compliance within an additional year. The result is that qualifying reliability critical units may come into compliance within up to 5 years. This pathway is structured to maintain reliability, to ensure CAA compliance and to increase certainty for sources in planning by allowing a unit owner/operator to determine whether it qualifies for a compliance schedule well in advance of the MATS compliance deadline.

The EPA believes that there will be few, if any, situations in which it will be necessary to have recourse to the processes discussed in the document just described, and that there are likely to be fewer, if any, cases in which it is not possible to mitigate a reliability issue within the further year contemplated under that document. However, there is always the possibility that some unit owner/operator will be unable to address its reliability issues within 5 years and there is always the possibility that a unit owner/operator will be unable to timely comply with the MATS for some other reason. Consistent with its longstanding historical practice under the CAA, the EPA will address individual non-compliance circumstances on a case-by-case basis, at the appropriate time, to determine the appropriate response and resolution.

A number of commenters also raised concerns about inconsistencies between the compliance timelines under this final rule and existing state agreements with specific owners/operators to install pollution control equipment and/or retire EGUs. The EPA believes the flexibilities provided in this discussion allow for some discretion to address those cases, but that they may not be fully addressed. The EPA is supportive of such efforts and believes they can have important multi-pollutant health and environmental benefits. To the extent that the flexibilities discussed here do not fully address a particular situation, we encourage states and sources to contact the EPA as early as possible to discuss their individual circumstances.

G. Cost and Technology Basis Issues

1. Dry Sorbent Injection

Comment: Several commenters stated that there is limited commercial operating experience in using DSI to control acid gas emissions from coal-fired boilers. They suggest that the technology is not adequately proven for use in this application.

Other commenters disagree with statements made that DSI is not proven. One commenter stated that DSI is a mature technology. The commenter indicated that DSI is well suited for units that burn fuels with lower or mid-level sulfur contents, and is among the viable options available for a number of sources to achieve the proposed HCl limits. Thus, the commenter believes that DSI represents a real technology control option for many units, and is among the suite of technology options that certain units will be able to employ to meet the proposed HCl limit.

Response: As explained in this response and elsewhere in this preamble, the EPA agrees that DSI technology is proven and ready for commercial use in controlling acid gases from coal combustion. One of the largest coal-burning electric utilities in the U.S, American Electric Power (AEP), pioneered the practical use of DSI with trona, a sodium-based sorbent, for SO_3 mitigation. American Electric Power has implemented trona injection for that purpose across its entire bituminous coal-fired fleet where both SCR and wet FGD systems are in place.[334] Examples of coal-fired EGUs already using trona DSI to control SO_2 emissions include NRG Energy's Dunkirk Generating Station Units 1–4 and CR Huntley Units 67 and 68 in New York.[335] The Dunkirk units range in size from 75 MW to 190 MW. Much larger units may also be economic when using DSI for SO_2 control, as suggested by Dominion Energy's studies of adding DSI on two

[334] *SO_3 Control: AEP Pioneers and Refines Trona Injection Process for SO_3 Mitigation,* Coal Power, March 2007, *http://www.coalpowermag.com/plant_design/SO3-Control-AEP-Pioneers-and-Refines-Trona-Injection-Process-for-SO3-Mitigation_29.html.*

[335] NRG Energy letter to RGGI, Inc, November 22, 2010, *http://www.rggi.org/docs/NRG_Nov_2010.pdf.*

625 MW units at the Kincaid plant in Illinois.[336] One of the largest suppliers of air emission control systems in the world, vouches that DSI is commercially proven for acid gas control:[337] [338]

Comment: Numerous comments were received on EPA's IPM modeling of DSI in the MATS analysis. A few commenters stated that DSI will not work on bituminous coals. Some commenters stated that DSI is only suitable for use on low sulfur, low chlorine western coals. Others stated that DSI is only likely to be used on relatively small units, and that larger units would use scrubbers for acid gas control. Several commenters expressed the opinion that because there is little commercial operating experience in using DSI to control SO_2 emissions from coal-fired boilers, EPA's IPM modeling assumptions on the efficacy and cost of the DSI control option are unjustifiably optimistic. Some commenters believe that DSI will not be as economic or as widely applicable for either SO_2 or HCl control as projected by EPA's IPM modeling. Commenters observe that wet or dry scrubbers for FGD, longer-standing control technologies for SO_2 and HCl, are more complex systems with a much higher capital cost than DSI. These commenters argue that the sector will need to retrofit many more FGD scrubbers than projected by IPM for MATS compliance and will therefore experience a much higher overall cost of compliance than projected by IPM, as well as needing more time and resources for retrofit construction. A few commenters suggested that EPA should base its MATS modeling on this more conservative outlook. A few commenters were concerned that EPA's DSI modeling assumptions relied on performance data from only one DSI vendor.

Some commenters were concerned that fly ash currently sold for beneficial uses will become unsalable because it will be contaminated by injected sodium-based DSI sorbents. Two commenters argued that EPA's IPM analysis understates DSI cost by not including the costs of foregone fly ash sales revenue and contaminated fly ash disposal. A few commenters observed that landfilling of sodium-based DSI solid wastes will produce leachate containing sodium and other compounds that are challenging to handle, thus requiring special landfill designs and a high cost for landfill disposal of DSI waste.

Response: The EPA believes that its representation of DSI in MATS compliance modeling is reasonable, is properly limited to applications that are technically feasible, and reflects a conservative approach to modeling future use of this technology.

The EPA disagrees that its IPM modeling of DSI is overly optimistic and therefore underestimates the costs of MATS compliance. In its IPM modeling, EPA restricts the availability of the DSI option to only those units that use or switch to relatively low sulfur coal: Less than 2 lb SO_2/MMBtu (*see* IPM documentation in the docket). The EPA's IPM projections for MATS compliance, therefore, already include the costs of any additional FGD scrubbers that are economically justified and projected for use on units using higher sulfur coals. The EPA models DSI assuming fine-milled trona as the injected sorbent. As mentioned by several commenters, sodium bicarbonate (SBC), which is processed from trona, is also suitable for use with DSI. Sodium bicarbonate is more reactive with acid gases than trona. It would require less tonnage of sorbent and less tonnage of waste disposal than trona for the same SO_2 removal effect, albeit at somewhat higher sorbent cost. Non-sodium based sorbents such as hydrated lime (calcium based) could also be used. Therefore, EPA's modeling of DSI technology does not include the full spectrum of sorbent choices that real-world applications enjoy, meaning that there may be opportunities for lower-cost applications of DSI that are not captured in EPA's projections for MATS. The EPA models DSI with trona injection rates corresponding to 70 percent SO_2 removal for all coals, assuming that an equivalent amount of sorbent is needed to provide 90 percent HCl removal, regardless of the low sulfur and chlorine content of western coals.

Senior technical staff from the EPA have carefully evaluated the key assumptions regarding the cost and operation of emission control technologies. In general, these staff believe that trona should have strong HCl reaction selectivity and, consequently, EPA's assumed trona injection rates may be overstated. The extent to which this assumption may actually overstate DSI control costs can be observed through DSI pilot testing for Solvay Chemicals by the Energy & Environmental Research Center (EERC) at the University of North Dakota.[339] The EERC's testing of trona DSI on a central Appalachian bituminous coal (1.3 lb SO_2/MMBtu) substantiates the strong HCl reaction selectivity of sodium-based sorbents, including trona, and calcium-based hydrated lime. The EERC's pilot testing shows that fine-milled trona, when well mixed into 325 °F flue gas upstream of a FF, provides 90 percent HCl removal at a SO_2 removal rate of less than 20 percent (as compared to EPA's modeling assumption of aligning 90 percent HCl removal with sorbent injection designed to achieve 70 percent SO_2 removal). The data show that 95 percent or higher HCl removal is readily obtained at somewhat higher SO_2 removal rates. Similarly strong HCl selectivity results were obtained using trona and an ESP at 650 °F. Test data from United Conveyor [340] on full-scale units also show these high HCl selectivity trends. Overall, these test data from multiple major vendors suggest that even if a SO_2 removal rate of 30 percent were required in order to obtain 90 percent HCl removal in the imperfectly mixed flow of a full-scale unit, it still appears that EPA's assumed trona injection rates may be as much as twice as high as would actually be needed in practice for certain applications. It is apparent that if EPA were to re-analyze MATS compliance with DSI injection rates reduced by 50 percent, there would be a corresponding reduction in the sorbent and related waste disposal costs that constitute most of the cost of using DSI.

Given the EERC test data, it is also apparent that most units that have ESPs and are burning low sulfur western coal could meet the HCl limit using DSI without the addition of a FF. If EPA were to re-analyze MATS compliance while allowing DSI use without the need for a downstream FF, it is apparent that there would be a very significant reduction in the overall number of FF retrofits projected, and a corresponding reduction in annualized capital costs. For the MATS proposal, the EPA modeled DSI on the assumption that all chlorine in coal converts to HCl, and that DSI would be the only mechanism by which the unit could prevent HCl from being emitted. Based on public

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[336] Dominion Energy, *BART Analysis for the Kincaid Power Plant,* January 2009, *http://www.epa.state.il.us/air/drafts/regional-haze/bart-kincaid.pdf.*

[337] Dry Sorbent Injection Systems for Acid Gas Control, Babcock & Wilcox, 2010, *http://www.babcock.com/library/pdf/ps-451.pdf.*

[338] Technologies for Acid Gas Control, Babcock & Wilcox, 2011, *http://www.babcock.com/library/pdf/ps-457.pdf.*

[339] Solvay Chemicals, Inc., HCl Removal in the Presence of SO_2 Using Dry Sodium Sorbent Injection, *http://www.solvair.us/SiteCollection Documents/presentations/20111214_hcl_presentation.pdf.*

[340] United Conveyor Corporation, *Dry Sorbent Injection for Simultaneous SO_2, HCl, and Hg Removal,* October 2011, *http://unitedconveyor.com/uploadedFiles/Systems/Systems_Sub/McIlvaine%20Multipollutant%20Removal%20Oct%202011.pdf.*

comments and a more thorough review of the ICR data, the EPA has introduced in final MATS modeling a recognition that the relatively high alkalinity of ash from subbituminous and lignite coals "removes" much of the HCl that would otherwise be emitted from combustion of these particular coals. The 2010 ICR data indicate that in some cases the ash itself removes sufficient HCl from these coals for MATS compliance; in effect, these acid-gas emissions are absorbed by coal ash and are captured by particulate control devices instead of being emitted in gaseous form. As a conservative measure, EPA's revised final MATS modeling assumes that 75 percent of HCl is removed by the ash for these coals. In the event that ash capture in practice is more effective than this 75 percent assumption, then EPA's analysis projects a conservatively higher level of DSI installations (and, thus, compliance cost) than would actually occur in practice. In any case, it appears that significantly less sorbent injection would actually be required in practice than assumed by EPA for these low sulfur, low chlorine coals, and that the IPM projected DSI operating costs are likewise higher for these coals than would be experienced in practice.

The EPA models DSI with sorbent injection occurring downstream of an existing electrostatic precipitator (ESP). The existing ESP is assumed to remain in service. The model adds a fabric filter downstream of the DSI injection point to capture the small amount of PM passing through the ESP plus the reacted and unreacted DSI sorbent. Most of the DSI projected by IPM, therefore, includes the costs of a retrofitted FF. This modeled configuration allows fly ash currently captured in ESPs to remain uncontaminated by DSI sorbent and, therefore, remain available for sale and beneficial use. The EPA conservatively models FF costs based on an assumed full-size system with an air-to-cloth ratio of 4.0. The FF costs could be somewhat less in practice if a smaller system (with an air-to-cloth ratio of 6.0) were used for the reduced DSI dust loading. The EPA observes that some of the owners of units with ESPs may chose to convert existing ESPs into FFs,[341] an option not modeled in IPM, but that would likely have a lower capital cost than a retrofitted FF. In the MATS proposal EPA modeled DSI with a waste disposal cost of $50/ton, based on a Sargent & Lundy DSI cost model prepared for EPA (*see* proposal IPM documentation in the docket). The EPA has continued to model DSI at this waste disposal cost for analysis of the final rule. However, recent discussions between senior technical staff from the DOE and the EPA have suggested that in some situations sodium sulfates, that would be formed by the injection of trona, could potentially leach out of the fly ash/sorbent mixture on contact with water. Although the technical staff recognized that these concerns are more relevant to bituminous coal-fired units where ashes are not cementitious, unless mixed with limestone or lime, they suggested that the impacts of potentially higher disposal costs be evaluated. Based on public comments, further investigations by Sargent & Lundy, and suggestions from the EPA and DOE technical staff, EPA's analysis of the final rule has included an IPM sensitivity case using a DSI waste disposal cost of $100/ton. The sensitivity case indicates that a 100 percent increase in assumed DSI waste disposal cost produces slightly less than a 1 percent increase in the projected cost of the rule.

Comment: A few commenters expressed the concern that there is an inadequate supply of trona to support DSI operations at the levels projected by the EPA for MATS compliance.

Response: The EPA projects that just over 50 GW of coal-fired capacity might retrofit with DSI for MATS compliance, thus reducing SO_2 emissions by about 1 million tons per year. Based on conservatively high trona injection rates, as discussed above, the EPA estimates that the amount of trona required to support DSI operations at this level is about 4 million tons per year. By comparison, the trona mining industry in the U.S. has a demonstrated production capacity of at least 18 million tons annually, and was running well below that capacity (16.5 million tons) in 2010.[342] [343] If the EPA's assumed trona injection rates are as much as 50 percent greater than actually needed for at least 90 percent HCl control, as discussed above, and given that some subbituminous coals will apparently need little or no sorbent injection for HCl control, there may already be an adequate surplus of trona production capacity to support DSI for MATS compliance. The EPA, therefore, concludes that trona supply for DSI is either already adequate, or will require at most a small increase in production capacity.

For all of these reasons, the EPA believes that its representation of DSI in MATS compliance modeling is reasonable, is properly limited to applications that are technically feasible, and reflects a conservative approach to modeling future use of this technology.

2. Economic Hardship

a. Job Losses and Economic Impacts

Comment: Several commenters indicated that they believe the proposed rule will weaken industry, cause job losses and hurt power consumers. One commenter reported that the proposed rule will affect 1,350 coal and oil-fired units at 525 power plants and that NERC reports that by 2018 nearly 50,000 MW of capacity will be retired by the proposed rule. Many of these commenters compared the cost estimated by EPA to a variety of other sources that estimate substantially higher costs of the rule. The commenters expressed concern that electricity price increases are likely to be up to 24 percent in some regions as a result of the proposed rule. In addition to the economic difficulty the proposed rule could place on consumers, the commenter believes that many in the energy sector will lose their jobs due to coal-fired capacity losses. The commenters believe the effects on coal-fired plants in the Southeast especially will mean the loss of high-paying, high-skilled jobs and drastic price increases in energy costs. Additionally, commenters expressed concern that increased electricity and natural gas prices would impact businesses in multiple sectors across the country.

Response: The EPA disagrees with the estimates presented by the commenters. The EPA has updated its analysis to reflect the final MATS. The Agency estimates the annual costs of the final rule in 2015 to be $9.6 billion in 2007 dollars. The estimate of early retirements of coal-fired units due to this rule is 4.7 GW, lower than the level estimated at proposal. Both of these estimates were prepared using the IPM, a model that has been extensively reviewed and has been utilized in several rulemakings affecting the power generation sector over the last 15 years. The Agency's analyses are credible and accurate to the extent possible, and all assumptions and data are made public. Limitations and caveats to these analyses can be found in the RIA for this rule.

The EPA estimates that there will be an increase of 3.1 percent in retail

[341] TW Lugar, *et al., The Ultimate ESP Rebuild: Casing Conversion To a Pulse Jet Fabric Filter, a Case Study,* Electric Power Conference, May 2009, *http://www.cecoenviro.com/uploads/ESP%20to%20Fabric%20Filter%20Baghouse%20Conversion%20-%20Buell%20Case%20History.pdf.*

[342] *http://www.wma-minelife.com/trona/tronmine/tronmine.htm.*

[343] *http://www.wma-minelife.com/trona/TronaPage2/trona_production.htm.*

electricity price on average in the contiguous U.S. in 2015 as an outcome of this rule, with the range of increases from 1.3 percent to 6.3 percent in regions throughout the U.S. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the Agency's analysis, as a result of this rule. To put this in context, the roughly 3 percent incremental increase in aggregate end-user electricity prices projected to occur over the next 4 years is about the same as the 3 percent absolute average change in total end-user electricity prices observed on an annual basis.[344] Furthermore, the roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[345] Even with this rule in effect, electricity prices are projected to be lower in 2015 and 2020 than they were in 2010.[346]

The Agency found that the readily discernible impact on long-term employment nationally within the most directly affected sectors should be small and the EPA also estimated that about 46,000 job-years [347] of one-time construction labor could be supported or created by this rule. This includes jobs manufacturing steel, cement and other materials needed to build pollution control equipment, jobs creating and assembling pollution control equipment, and jobs installing the equipment at power plants. Potential job increases from increased output by lower-emitting facilities (such as increased generation from well-controlled coal-fired plants that replace generation from older coal-fired plants) are expected to partially or fully offset potential job losses resulting from reduced output from higher-emitting facilities. The EPA analysis projects a net change in the directly affected EGU sector of between 15,000 net jobs lost to 30,000 net jobs gained on an annual basis.[348] See Chapter 6 of the RIA for further details.

The EPA has also looked at the possibility that changes in the price of electricity may influence the levels and geographic distribution of downstream economic activities, and associated employment. Projecting how potentially higher electricity prices may affect various downstream economic activities in particular regions as a result of this rule is challenging for several reasons: (1) There are significant uncertainties regarding projections of consumer- and location-specific electricity price changes in response to future firm-specific compliance strategies; (2) the availability of competitively-priced alternative energy sources (including energy conservation) and less electricity-intensive substitute goods and services may significantly mitigate potentially adverse economic consequences resulting from projected increases in electricity prices in ways which are not captured effectively in currently available models; and (3) available modeling tools are not configured to capture the effects over time of economically significant effects of cleaner air (*e.g.*, reductions in medical expenditures and improvements in labor productivity resulting from fewer lost work days) achieved by rules evaluated using single target year criteria pollutant and/or HAP benefits projections. After considering these methodological limitations, the Agency concludes that there is not a satisfactory methodology for projecting the downstream economic (including employment) effects of any changes in electricity prices due to this rule.

We expect the downstream economic effects of this rule to be small because electricity is only a small factor in the production of most goods and services.[349] A 3 percent increase in end-user electricity prices translates to a much smaller effect on prices and potential output of goods and services from end-users of electricity. Over time, the incremental effect of this rule on electricity prices is projected to diminish significantly; for example the difference in expected prices is projected to narrow from 3.1 percent in 2015 to 2.0 percent in 2020 as shown in Chapter 3 of the RIA.

Despite the absence of a satisfactory methodology for quantifying the potential economy-wide effects (including employment) of any potential increases in electricity prices resulting from this rule, the EPA expects the incremental effects of this rule on electricity prices to be small given the projected electricity price increases relative to historical levels and volatility in end-user electricity prices. Based on these projections and contextual information, the Agency believes that the incremental effects on electricity prices and economic activity of this rule are likely to be small relative to other factors influencing electricity prices, overall employment, and other aspects of economic activity.

Comment: Several commenters considered the proposed rule to be a tax on the American public, since utilities implementing upgrades will pass the costs on to the consumer. Commenters questioned the preference of Americans to subsidize renewable energy sources and put money into the proposed rule instead of other environmental programs with greater benefits. Commenters explained that the tax-like price increase reduces income of energy consumers and depresses business development. The commenters used California as an example of a state that uses low rates of coal-based electricity and cites companies that have left the state as a result of substituting higher cost forms of electricity for coal. A commenter stated that coal-derived energy will rapidly become more expensive, especially in the "rust belt" and Southeast region, as can be seen by the rate increase already requested in Louisville. A commenter believes the "indirect taxation" limits the ability of the economy to absorb the cost of retrofitting and new capacity projects, lowers discretionary spending and leads to job losses and lost tax revenues, given the restrictive timeframe for compliance.

Response: The Agency does not agree that this rule creates or alters any taxes on affected sources required under this rule to reduce their emissions of toxic air pollutants, nor are taxes created or altered or imposed on consumers of electricity which is provided to the market by affected sources. Moreover, unlike a tax, this rule does not generate government revenue. The rule does, however, indirectly address the problem of the "externality cost" of higher health risks and other adverse effects on the populations exposed to toxic air pollution emissions from affected sources. This rule may have the effect of

[344] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

[345] Ibid, EIA AEO 2010, Table 8–10.

[346] Ibid, EIA AEO 2010, Table 8–10 for price levels; and Chapter 3 of the RIA for electricity price differential.

[347] A "job-year" is a combined measure of jobs and job duration which is equivalent to one person being employed for one year. For example, 2 job-years could represent two years of employment for one worker, one year of employment for two workers, or 6 months of employment for four workers. Estimates of employment changes that involve non-permanent workers are usually reported in job years to give a sense of the total employment effects.

[348] It should be noted that if more labor must be used to produce a given amount of output, then this implies a decrease in labor productivity. A decrease in labor productivity will cause a short-run aggregate supply curve to shift to the left, and businesses will produce less, all other things being equal.

[349] BEA. (2007b). Commodity-by-Industry Direct Requirements after Redefinitions, 2002. Available in: *2002 Summary Tables, 2002 Benchmark Input-Output Data*. Retrieved from *http://www.bea.gov/industry/io_benchmark.htm#2002data*.

reducing or eliminating a market distortion that provides an implicit subsidy to affected facilities. This implicit subsidy results from the fact that some facilities currently can avoid the costs of toxic air pollution controls by imposing higher health and other costs on those who are exposed to higher levels of toxic air pollution. The Agency also disagrees with the implication that the costs incurred by less-controlled sources to bring their toxic air emissions in line with their better-controlled competitors will lead to significant or debilitating changes in market and economic conditions. The Agency's estimate of the potential increase in retail electricity price is an average of 3.1 percent in 2015, with a range of increases by region from 1.3 percent to 6.3 percent. As shown in Chapter 3 of the RIA, the higher rates of potential electricity price increase tend to occur in those regions where electricity prices have been relatively low, due to some extent to reliance on coal-fired units which have been cheaper to operate due to underinvestment in toxic air pollution controls.[350] As shown in Chapter 3 of the RIA, all regions with year 2015 projected percentage increases in retail electricity prices above the contiguous U.S. average are also projected to have baseline retail electricity prices which are below the contiguous U.S. average price level in that year. In addition, natural gas prices will only increase by 0.3 to 0.6 percent on average over the time horizon of 2015 to 2030. As discussed above, for consumers of electricity in the commercial and industrial sectors, electricity tends to be a fairly small fraction of total costs of production, implying that the average projected electricity price increase of 3 percent will lead to only a small fractional change in the costs of providing goods and services to the economy. While some residential electricity consumers may similarly see a small price increase in retail electricity prices, it should be noted that these consumers tend to reside in the same area or region as the affected facility and so will also experience the improvement in air quality from the reductions due to the rule. The reduction in health risk and other improvements to quality of life associated with lower exposure to toxic and other air pollutants achieved by this rule will confer benefits on these consumers which include lower risks of premature mortality, lower morbidity, and improved productivity and competitiveness of U.S. workers due to reduction in work days lost to air pollution-related illness. The benefits of these improvements are projected to exceed costs of compliance by affected sources by at least six-fold. The potential price increases in electricity and natural gas should be considered in light of the substantial health, welfare, and economic benefits achieved by this rule.

Comment: Many commenters expressed support for the EPA's impact analysis and disputed claims by other commenters that the projected rule will harm economic growth. A number of commenters mentioned testimonials by power company CEOs stating that the proposed rule will not affect the economic health of the industry and a survey showing nearly 60 percent of the coal-fired units already comply with the EPA's proposed Hg standard, and several other meaningful quotes from utility executives. The commenters also pointed out that 17 states already require plants to address Hg pollution, with some imposing more stringent emission limits than the EPA proposes. The commenters believe that utilities use the threat of power plant closures and lost jobs to delay Hg reductions from coal-fired plants. Commenters also believe that the rules will drive innovation and job creation as new technologies to reduce pollution are created. Several commenters quoted the Economic Policy Institute finding that the proposed rule will increase job growth by 28,000 to 158,000 jobs by 2015 (including approximately 56,000 direct jobs and 35,000 indirect jobs), the University of Massachusetts study that showed an increase 1.4 million jobs in 5 years, and the Constellation Energy Group installation project that employed nearly 1,400 skilled workers. Commenters also cited the University of Massachusetts study statement that a net gain of over 4,200 long-term operation and maintenance jobs will result.

Several commenters observed that the positive impacts of the rule strongly favor its adoption. These commenters stated that, contrary to the unfounded assertions by critics of EPA and the rule, EPA has conducted a technically sound and conservative benefit-cost analysis showing that the proposed rule's estimated benefits are at least five times as high as its costs. One commenter stated, "With sound, albeit unduly conservative, econometric modeling, EPA has also determined that the Toxics Rule will promote economic growth and create jobs in both the long and short term." Two commenters cited the EPA impact analyses by Dr. Charles Cicchetti which confirm this finding and state that the analysis underestimates the rule's net benefits and positive impacts on the nation's economy. By considering some benefits not monetized in the EPA analysis, Dr. Cicchetti concludes that the proposed rule will create $52.5 to $139.5 billion in net benefits annually, create 115,200 jobs, generate annual health savings of $4.513 billion, annual increases in GDP of $7.17 billion and $2.689 billion in additional annual tax revenues, and spur innovation and modernization of EGUs. The commenters state that the study findings show no need to delay implementation of the rule or needlessly duplicate economic analyses already completed.

Commenters reported that multiple researchers confirmed that the EPA's estimates of economic stimulus are conservative and that the proposed rule will stimulate job growth. A commenter quotes Dr. Josh Bivens of the Economic Policy Institute, who also found that EPA's conclusions were conservative. Dr. Bivens concluded, "The EPA RIA on the proposed toxics rule makes a compelling case that the rule passes any reasonable cost-benefit analysis with flying colors—the monetized benefits of longer lives, better health, and greater productivity dwarf the projected costs of compliance * * * Whether regulation in general and the toxics rule in particular costs jobs is an empirical question this paper attempts to answer. In particular, this paper examines the possible channels through which the proposed toxics rule could affect employment in the United States and finds that claims that this regulation destroys jobs are flat wrong: "The jobs-impact of the rule will be modest, but it will be positive." His report details the following major findings:

1. The proposed rule would have a modest positive net impact on overall employment, likely leading to the creation of 28,000 to 158,000 jobs between now and 2015.

2. The employment effect of the [MATS] on the utility industry itself could range from 17,000 jobs lost to 35,000 jobs gained.

3. The proposed rule would create between 81,000 and 101,000 jobs in the pollution abatement and control industry (which includes suppliers such as steelmakers).

4. Between 31,000 and 46,000 jobs would be lost due to higher energy prices leading to reductions in output.

5. Assuming a re-spending multiplier of 0.5, and since the net impact of the above impacts is positive, another 9,000 to 53,000 jobs would be created through re-spending.

[350] *http://www.epa.gov/airmarkets/images/CoalControls.pdf.*

Response: The EPA thanks the commenters for these observations. The Agency's estimates of employment impacts, found in the RIA for the rule, are smaller than those identified by the some commenters, though the EPA uses a different methodology that focuses on impacts specific to the electric power sector.

b. Impacts on Low-Income Consumers

Comment: Commenters expressed concern that the EPA's overview of the price increases does not consider the hardships that will be the reality of increased prices on low-income or fixed-income households or small businesses. The commenter reports increases of $90 million in capital costs, $11.4 million in annual operating costs and $6.4 million in annual debt service costs to achieve compliance, which will lead to a 13 percent increase in rates for the proposed rule, and a 41 percent increase for all proposed and new regulation compliance costs. The commenter argues against the EPA's view that energy efficiencies will offset rate increases, because low income customers will need to use less electricity due to economic necessity. The commenter also sees large price increases for customers if units are converted to natural gas, which is approximately 2.5 times more expensive than the coal that the commenter currently uses to generate electricity.

Response: The EPA's estimates of increase, relative to the baseline, in the retail electricity price range from 1.3 percent to 6.3 percent regionally in 2015, with an average increase nationwide of 3.1 percent in 2015. Low-income households will thus see some increase in electricity price, but this increase should be modest. In addition, the increase in the price of natural gas as a result of this rule is expected to be 0.3 to 0.6 percent over a time horizon of 2015 to 2030. This increase in price is low enough that electricity customers should not experience a major increase in price resulting from any modest changes to electricity generated by natural gas. The roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[351]

[351] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

c. State or Regional Impacts

Comment: Multiple commenters expressed concern over the impact of the rule on electricity prices and reliability in specific states or regions. These commenters were concerned that these impacts would adversely affect specific industries such as construction and manufacturing. One commenter suggested the EPA consider regional differences that will impact system reliability and costs, such as the increased impacts on regions relying heavily on coal and oil and encourages cooperation between the EPA and state and federal energy and environmental regulators.

Response: The Agency has studied possible impacts on resource adequacy as a result of this rule, and has determined that these impacts should not be significant. Furthermore, industry, along with relevant federal agencies, has the tools needed to address any reliability concerns. The Agency has prepared an updated feasibility TSD in support of the final rule, which is in the docket for this rulemaking.[352] The Agency has considered impacts on a regional basis as part of its overall analyses done using the IPM; these results are documented in the RIA for the rule and in the feasibility TSD.

The EPA's analysis shows that retail electricity price increases will not fall disproportionately on a specific region. In fact, those regions experiencing the largest change in prices are projected to have retail electricity prices below the national average both in the absence of MATS and after the implementation of MATS. In Chapter 3 of the RIA, the EPA presents retail electricity prices by region in 2015, for both the base case and MATS policy case. The six regions that are projected to have retail electricity prices above the national average price in 2015 in the absence of MATS are projected to have increases that are below the national average increase following the implementation of MATS. Those regions that have projected retail electricity price increases that are above the national average are all projected to have retail electricity prices below the national average in the absence of MATS.

Comment: A commenter quoted National Mining Association statistics showing coal is responsible for $65.738 billion in annual economic activity, produces 1,798,800 jobs and $36.345 billion in annual labor income. The commenter reports that regions such as Appalachia, the Midwest and Rocky Mountain West will be significantly affected by the proposed rule, including increased unemployment. Other commenters stated that communities near existing coal-fired generation units will be especially hard-hit if the plants are permanently retired. The communities will suffer from job loss and diminished tax revenue.

Response: The Agency's analysis, as found in the RIA, shows that impacts to these regions are mixed. For Appalachia, coal production is projected to fall by 6 percent in 2015, while the Western coal producing region will experience a decrease of 3 percent in production in 2015. The Interior region is projected to see a 9 percent increase in production. Retail electricity prices are expected to increase by 1.3 percent to 6.3 percent in various parts of the country in 2015. Also, the estimated number of early retirements according to the Agency that may result from this rule is 4.7 GW in 2015, or less than 2 percent of all U.S. coal-fired capacity in that year. Thus, there may be some negative impacts from this rule in some regions, but these same regions will also experience some of the benefits, such as reduced premature mortality from less exposure to $PM_{2.5}$ emissions as shown in Chapter 5 of the RIA. As discussed previously, the EPA's analysis shows that retail electricity price increases will not fall disproportionately on a specific region. In fact, those regions experiencing the largest change in prices are projected to have retail electricity prices below the national average both in the absence of MATS and after the implementation of MATS.

The results of the EPA's employment analysis, found in Chapter 6 of the RIA, indicate that the final MATS has the potential to provide significant short-term employment opportunities, primarily driven by the high demand for new pollution control equipment. While the employment gains related to the new pollution controls are likely to be tempered by some losses due to certain coal retirements, some of these workers who lose their jobs due to plant retirements could find replacement employment operating the new pollution controls at nearby units. Finally, job losses due to reduced coal demand are expected to be offset by job gains due to increased natural gas demand, resulting in a small positive net change in employment due to fuel demand changes.

While shifts in employment are difficult for those directly affected, and the Agency remains concerned about the challenges job shifts can bring to the

[352] *See* "An Assessment of the Feasibility of Retrofits for the Mercury and Air Toxics Standards Rule" in the docket.

individuals affected, Bureau of Labor Statistics data indicate that compliance with pollution control requirements is a relatively very small contributor to overall employment shifts in the U.S. economy. Specifically, the main cause of mass layoffs over the last four years according to 2007 to 2011 Bureau of Labor Statistics data is "lack of business demand," accounting for over 40 percent of the layoffs reported by industry. In contrast, all types of regulatory actions (including health, safety, and environmental) by all levels of government (Federal, State, local) combined were cited as the primary factor in only 0.2 percent of mass layoffs over the same period.[353]

d. Retirements of Coal-Fired EGUs and Shutdowns

Comment: A commenter discussed the economic factors behind EGU retirements. These factors include the cost of alternative generation using natural gas, the cost of implementing demand response measures that can be bid into capacity markets, and the cost of continuing to generate power from an existing unit. The commenter states that regardless of the costs associated with the Toxics Rule and other EPA electric power industry regulations, some power plants were already economically unsustainable. The commenter quotes M.J. Bradley, who points out, "[o]f the 122 coal units in PJM with capacity less than or equal to 200 MW, 35 failed to recover their avoidable costs and another 52 were close to not recovering those costs. Therefore, in PJM * * * in addition to approximately 10 GW of coal generation that has or will be retired during the 7 years from 2004 to 2011, another 11 GW faces a troubling economic outlook." The commenter provides confirmation of this by the most recent PJM capacity auction, where approximately 6.9 fewer GW of coal-fired capacity cleared the auction (1.85 fewer GW were offered) as compared with the prior year's auction, and an additional 4.836 GW of new demand response (energy efficiency) resources cleared the auction. Thus, the commenter states, some claims linking retirements to the MATS are overstated and misleading. The commenter gives the example of the American Electric Power attempt to link its planned plant closures to the MATS, but those plants already are slated to either close or to upgrade controls to comply with existing laws. The commenter goes on to quote three independent studies that support the finding that over 50 percent of the fleet is equipped with scrubbers and the number will increase to nearly ⅔ by 2015.

Response: The EPA agrees with the findings of the independent studies mentioned by the commenter.

e. Impacts on Mining

Comment: Multiple commenters mention the proposed rule's impact on mining. One commenter mentioned increasing energy costs for the U.S. mining industry, resulting in fewer projects and associated jobs, as well as increasing dependence on foreign mineral resources. Commenters see mining impacts being disproportionally large for lignite mines, which are dependent on their co-located lignite-fired power plants. The commenters state that if the plant closes, there is no market for the lignite and the mine will also close, displacing plant workers. These impacts are largest in Texas, the largest coal consuming state and fifth largest coal producing state, as well as a deregulated electricity market. One commenter pointed out that the Texas coal market provided a buffer against natural gas price volatility and in particular believes the proposed rule does not take into account the emission reductions already achieved by industry in general and their company in particular. A commenter stated that impacts will be magnified in Texas, since it is the largest coal consuming state and mines lignite. A commenter indicated they believe it is unclear the extent to which EPA includes the impacts on the mining industry that will result from this rule.

Response: The Agency presents impacts on the coal mining sector from this rule in the RIA. Given the modest increase in coal and other energy costs associated with the rule, the Agency does not expect widespread impacts on coal mining. The Agency's modeling accounts for all emission controls and programs installed and/or implemented up through December 2010, including those in Texas.

f. Flexible Regulations

Comment: Several commenters expressed concern over the potential impacts of the regulation and believe that the requirements should be more flexible in order to mitigate these impacts.

Response: The EPA believes the requirements of the final rule have been made as flexible as possible consistent with the CAA. The final rule allows some flexibility, including allowing averaging across units in the same subcategory at a facility, allowing for an option of an input or output standard for existing units, and allowing for alternative compliance options (*e.g.*, for coal, filterable PM or total non-mercury metallic HAP or individual HAP metals). In addition, the Agency is not prescribing specific technologies as part of this final rule, but instead requiring emissions limitations be met. This approach allows the industry to find the most cost-effective approach to meeting the requirements while ensuring considerable public health benefits.

g. Temporary vs. Permanent Jobs

Comment: A commenter expressed disagreement with the EPA prediction of new jobs created, because the commenter believes far more plants will shut down than the EPA predicts, resulting in higher job losses. The commenter also pointed out that while jobs running power plants are permanent, the jobs predicted to be created by the proposed rule are short term construction jobs, and will all occur in the same short timeframe for compliance. The commenter also stated that the EPA estimate does not include the opportunity cost of lost construction jobs due to new power plants that will not be constructed due to the proposed rules.

Response: The Agency believes that the employment impacts of the final rule will be small, as has been the case historically with regards to environmental regulation. The Agency does provide an estimate of the long-term employment impacts to the electric power sector in the RIA for the rule, and that estimate shows a range of impacts from 15,000 net jobs lost to 30,000 net jobs gained (all annual), but also recognizes important limitations to these estimates. The Agency's estimate of impacts to short-term jobs, including those in construction, accounts for both losses and gains that result from the rule. This is shown in Chapter 6 of the RIA.

Comment: Commenters believe that installation of new pollution controls would be a job-growth opportunity in their states because money spent on controls for power plants creates high-quality jobs in steel, cement and other materials, as well as in the assembling of the equipment as well as installing and operating it. A commenter shares the Alabama Fisheries Association estimate that the water-based recreation industry brings in over $1 billion per year to the state's economy though the state ranks third for imperiled fish with 61 bodies of water cited for Hg contamination. The commenter believes the HAP accumulating in the waterways

[353] U.S. Bureau of Labor Statistics, 2011. Extended Mass Layoffs in 2010. *http://www.bls.gov/mls/mlsreport1038.pdf.*

threatens the industry with permanent job-losses and lost revenue.

Response: The Agency agrees with the commenter that the reduction in HAP that will take place as a result of the rule over time will help to improve waterways in Alabama and thus help the water-based recreation in that state. More information on the benefits of Hg and other HAP reductions can be found in Chapter 4 of the RIA for the rule. The Agency also agrees with the commenter that the addition of control equipment for EGUs may stimulate employment in a variety of industries.

h. Natural Gas

Comment: A commenter states that natural gas use is only an option in places where infrastructure exists to supply sufficient natural gas to the EGU and other local needs and reports that year-round reliable gas delivery is rare due to requirements to meet the other needs. The commenter says that gas interruptions are prevalent in the winter, but can happen year-round, and the costs of establishing a natural gas line to a power plant can be tens of millions of dollars or more, and moving a plant to a gas source can take many years. The commenter describes the options for a Norwalk Harbor plant, and explains that the modifications are costly and difficult even before considering the modifications needed to alter the boiler and fuel supply system to allow natural gas combustion.

Response: The final rule does not prescribe either pollution control technologies to be used, nor does it dictate the types of fuels that should be burned. The requirements of the final rule are designed to allow industry to find the most cost-effective approach to addressing harmful emissions that are covered by this action. The Agency believes that cost-effective technologies exist today and have been deployed on many power plants, and utilities will be able to find intelligent solutions to address harmful emissions. The EPA has provided supporting information as part of the preamble and RIA for this rule, along with the feasibility TSD, which demonstrate the availability and performance of technologies to meet the requirements of the final rule.

Comment: A commenter discusses the factors that could lead to higher natural gas prices not currently reflected in the EPA impact projections, including industrial load and demand not rebounding to 2008 levels and the influence of liquefied natural gas exports. The commenter asks that the EPA address a variety of factors related to its natural gas assumptions.

Response: The Agency has fully documented its assumptions and framework for modeling natural gas in IPM for both the proposed and final MATS. This information can be found in Chapter 10 of the IPM documentation (*http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter10.pdf*). The documentation provides a thorough overview of the natural gas module, describes the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. Also documented are the resource constraints, liquefied natural gas (LNG), demand side issues, the natural gas pipeline network and capacity, procedures used to capture pipeline transportation costs, natural gas storage, oil and natural gas liquids (NGL) assumptions, and key gas market parameters.

i. Compliance Timeline and General Timeline

Comment: A commenter states that the proposed rule will require costs be passed on to consumers, meaning state public utility commissions will be flooded with requests for rate increases from utilities trying to recover expenditures. The short deadline will also result in a large number of extension requests made to state permitting authorities, further burdening them.

Response: The compliance date for this rule for existing sources will be 3 years and 60 days after publication of the final rule in the **Federal Register**, or approximately March 2015. Thus, there will be some time before the impacts of this rule such as any increase in retail electricity prices become a concern. It also should be noted that increases in retail electricity prices will be 3.1 percent on average in 2015, with a range regionally from 1.3 percent to 6.3 percent.

Comment: A commenter reports that they will need to install add-on pollution controls to meet the proposed emission standards as well as implement other physical or operational changes. The commenter expresses concern about the number of pre-construction steps that would be required, as well as the new construction activities and the challenges of scheduling sequence relative to interconnections and other tie-in considerations involved in compliance.

Response: The Agency has addressed concerns with the feasibility and timing of control installations in its report on the subject (*see* feasibility TSD contained in the docket for this rule).

Comment: Multiple commenters do not believe that labor availability will constrain control installation in the required timeframe and cites an Institute of Clean Air Companies (ICAC) response that it will not for these reasons:

1. The power sector has demonstrated ability to install large number of systems in short time period;

2. The majority of coal plans have installed control systems already;

3. Fewer resource and labor-intensive control options being used for compliance; and

4. End users have utilized cost reducing and implementation efficiency strategies for efficient deployment of technologies.

Another commenter states that a wide range of technical and economically feasible practices and technologies are available currently to meet the emission limits and are in use around the country.

Response: These comments are generally consistent with the conclusions of the Agency's analyses on feasibility of control installations for this rule as found in the feasibility TSD in the docket for this rulemaking.

j. Burden Outweighs Environmental Gain

Comment: Several commenters state that the EPA has no data relating to benefits from reducing non-mercury HAP, so the costs of the proposed rule exceed the HAP benefits by 29,000 times. One commenter states that the impact analysis was largely focused on Hg with little support for other HAP reductions and failed to provide account of true costs and benefits.

Response: While we are not able to monetize the benefits from reductions of non-mercury HAP that will take place, these important effects are discussed qualitatively in Chapter 4 of the RIA. The quantified benefits of this rule include the reductions in non-HAP emissions such as SO_2 and $PM_{2.5}$ that will occur as a co-benefit of this rule as modeled by EPA. The total benefits are estimated to outweigh the total annual costs of the rule by a margin of either 3 to 1 or 9 to 1, depending on the benefits estimate and discount rate used. These reductions are credible and are considerable in size. The estimates of these benefits reflect the latest scientific understanding on the subject. More information on the estimates and

the methodology for their preparation can be found in the RIA for the rule.

Comment: Several commenters consider the proposed rule to be the most expensive clean air rule ever. They point out the estimated $10.9 billion annual cost in 2015 and approximate 1,200 existing coal-fired EGUs affected, both of which were estimated by the EPA. Commenters believe the EPA's estimates are incorrect and the true cost will be far more, due to cumulative effects of all proposed power sector rules, and indirect costs from job losses, reduced productivity and competitiveness resulting from electricity costs. They ask the EPA to keep these high costs in mind when evaluating impacts of the proposed rule and consider the costs with respect to the benefits. One commenter requests that the EPA explain how its approach utilized "the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible" and includes analyses by EIA, EEI, NERC, NERA, Credit Suisse, ICF, and Burns & McDonnell.

Response: As noted earlier, the Agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: (1) The various EO requirements that the Agency must comply with require us to estimate impacts specific to this rule; (2) decisionmakers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; and (3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, EPA makes clear statements about the impacts, costs, and benefits that are estimated as a result of this particular regulation.

This does not, however, mean EPA has failed to incorporate these regulations into this analysis. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the Agency does reflect on the cumulative impacts of our regulations. In March 2011, EPA issued the Second Clean Air Act Prospective Report which assessed the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at *http://www.epa.gov/air/sect812/feb11/summaryreport.pdf*). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments are estimated to reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at *http://www.epa.gov/air/sect812/prospective2.html.*

The direct benefits of the 1990 Clean Air Act Amendments and associated programs are estimated to significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits are estimated to exceed costs, combined with extensive uncertainty analysis, suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. The analysis presented in the RIA for the current regulation uses a similar methodology.

The techniques employed by the Agency for generating benefits and costs, and consider the most recent and complete data available to the Agency. The EPA recognizes that the analyses have caveats and limitations, and we discuss our analyses and their caveats and limitations in the RIA for the rule, as well as in the benefits section of the preamble. The Agency has also revised the cost analyses for the final rule to reflect data received in public comments on the proposed rule, and costs are lower than when the rule was proposed.

k. Impact on State Regulators

Comment: Several commenters expressed concern over the burden imposed on state regulatory agencies by the rule.

Response: The Agency has estimated the costs of implementation of the rule to states that own EGUs affected by the rule, and has included this analysis in the RIA. The Agency has updated this analysis for the final rule and it is included in the RIA. While the EPA has not prepared an analysis of the impacts of the rule on state programs, the Agency does not believe the rule will be unduly burdensome to the state regulatory agencies. The EPA works closely with state regulatory authorities to ensure that the rules are implemented properly, and the Agency will continue to do so in support of this final rule.

Comment: A commenter states that the reductions in SO_2 and $PM_{2.5}$ required by the proposed rule will assist state and local air pollution control agencies to meet health-based air quality standards, reduce haze and improve visibility. The commenter points out that substantial reduction in emissions made by the very large sources under the proposed rule will lead to fewer pollution controls needed at smaller sources to meet health-based ambient air requirements. This is a far more cost-effective approach than controls at smaller facilities and is the lowest cost path to improved public health and a cleaner environment.

Response: The EPA acknowledges that the HAP standards in this final rule will lead to considerable co-benefit reductions in PM and SO_2.

l. Miscellaneous

Comment: A few commenters discussed the impact of the rule on the federal budget deficit. One commenter points out that the proposed rule will affect the federal budget in two ways:

1. Direct compliance costs to electric generating units (EGUs) owned by federal agencies; and

2. Pass-through compliance costs paid in the form of higher prices for electricity purchased by federal agencies.

Response: The Agency estimates the direct compliance costs to EGUs that are federally owned as part of the overall cost analysis completed for the proposal and disclosed in the RIA for the rule. The Agency does not provide an estimate of the impact on federal agencies from higher electricity prices associated with the rule, however. This type of analysis is not required under EO 12866 and statutory requirements.

H. Testing and Monitoring

Comment: Commenters raised numerous issues with the testing and monitoring requirements for initial and continuous compliance. The following discussion highlights the comments and responses to a number of the critical issues and describe where the comments have resulted in a significant rule change or where we disagreed with commenters' suggestions of issues or need for changes in the rule. Additional comments and responses are addressed in the Response to Comments document included in the docket for the final rule.

Test Methods. A number of commenters suggested that we should allow for the use of Method 5B to determine compliance with the PM emission limit. In addition, a number of

commenters objected to the frequency of stack testing when used as the method for demonstrating continuous compliance. Commenters also objected to the requirement for testing one pollutant when the source was complying with an optional surrogate (or vice versa); for example, commenters objected to testing for HCl if a unit was complying with the optional SO_2 limit, or testing for metals if the unit was complying with the optional PM limit.

Response: Although Method 5B is specified for wet scrubber-controlled utility boilers under 40 CFR part 60, subparts D, Da and Db, we are excluding Method 5B for demonstrating compliance with the filterable PM emissions standard in this final rule. The extended high temperature heating of the filters prior to weighing as specified in Method 5B would introduce differences between the compliance test data and the data that underlie the filterable particulate standard. Because the test data that underlie and filterable particulate standard are based primarily on Method 29 and Method 5 data collected at 320 °F or comparable filterable particulate methods, we are specifying those same methods for determining compliance with the standard.

For stack test frequency, we modified the final rule to require quarterly testing to demonstrate continuous compliance. In addition, we agree that testing should be required only for the emission limits that your source is complying with, and, thus, the final rule does not require testing of both the pollutant and the surrogate.

Comment: Fuel Analysis Methods. A number of commenters raised various concerns with the fuel analysis methods specified in the proposed rule.

Response: Based on the comments received and a further review of the technical challenges associated with the proposed fuel analysis requirements, we have not finalized the proposed fuel analysis requirements. As the rule no longer requires operating limits based on fuel content or fuel analysis, the comments on this issue are largely moot. For LEEs, we agree that the proposed LEE ongoing eligibility requirements were overly burdensome and restrictive. As a result, existing solid or liquid fired units that qualify for Hg LEE status will be required to conduct a 30-day test for Hg using Method 30B each year. Neither fuel analysis nor adherence to an operating limit will be required. Should an annual test show ineligibility for LEE status, the source will revert to the requirements for Hg monitoring using CEMS or sorbent traps or, for oil-fired units, quarterly emissions testing. Existing solid or liquid fired units that qualify for non-mercury LEE status will be required to conduct a stack test every 3 years, and neither fuel analysis nor adherence to an operating limit will be required. Should the stack test show ineligibility for LEE status, the source will revert to using CEMS or PM CPMS or conducting quarterly emissions testing.

Comment: Operating Parameter Limits: Some commenters objected to the use of enforceable operating parameter limits, requested that the rule be more consistent with the compliance assurance monitoring program, and raised specific objections to certain parameters required for certain control devices. Commenters also raised concerns about a PM CEMS operating limit establishing a de facto more stringent PM emission limit than the one being tested for under the total PM standard in the proposal.

Response: We believe that continuous monitoring in the form of CEMS, sorbent trap monitoring systems, and PM CPMS, or frequent stack emissions testing are appropriate to ensure ongoing compliance with this final rule. We also agree with commenters that some of the monitoring provisions in the proposal may have been duplicative and unnecessary. In order to provide flexibility in the final rule, we have retained a source's ability to define an operating limit and to monitor using a PM CPMS as an option to periodic filterable PM emissions testing.

The final rule establishes the PM CPMS as an operating limit monitor and not a direct filterable PM emission monitoring requirement that meets PS 11 requirements. Although we recognize the importance of continued control device performance to ensure emissions minimization, we also are aware that other rules that apply to these units including, but not limited to, the Operating Permits rule, the Compliance Assurance Monitoring rule, the ARP rules, and the NSPS already require continuous monitoring in most cases. Those rules will remain in effect so the need to impose additional operating limits monitoring or CEMS on those units is much reduced.

The final rule also provides for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach. In that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of satisfying the requirements in Performance Specification 11 in Appendix B to 40 CFR part 60 and Procedure 2 in Appendix F to part 60. The EPA provided this option in response to the comments in order to provide a straightforward direct measure of compliance that some sources may want to implement.

Comment: Hg CEMS. Commenters raised a number of technical concerns about Hg CEMS. Many commenters requested modifications so that the requirements would be more consistent with 40 CFR part 75 monitoring requirements. Some commenters questioned the ability of the technology to demonstrate compliance with emission limits at very low levels especially for new sources. Commenters also opposed high data availability requirements given that the technology is new and difficult to operate and maintain.

Response: We indicated in the proposed rule the intent to adopt CAMR-based requirements for Hg monitoring in place of the general 40 CFR part 63 performance specifications and QA requirements. With CAMR, these operating and reporting requirements for Hg CEMS went through notice and comment rulemaking for the same sources as covered by this final rule. Although CAMR was set aside on other grounds, these technical specifications and QA requirements reflect significant input from stakeholders and analysis by the EPA to establish an appropriate foundation for Hg monitoring at electric utilities under the CAA. For the final rule, we have made conforming changes to ensure that this intent is carried out effectively throughout the rule text and Appendix A, as well as including certain additional clarifications based on the input received in response to the proposed rule. We have also removed a cycle time test as unworkable for certain types of Hg CEMS.

The final rule provides the option for use of either Hg CEMS or sorbent trap monitoring systems. We believe the record clearly shows these to be proven technologies each providing certain advantages. For existing and some of the new unit standards, the level of the NIST-traceable Hg gas standards will be adequate and consistent with existing applications of Hg CEMS. For the lowest limits and other applications where an integrated sampling system offers advantages, affected facilities may opt to use sorbent trap monitoring systems to comply. There are data in the recent draft report entitled "Determining the Variability Of CMMS At Low Hg Levels,"[354] that demonstrate reasonable

[354] *http://www.icci.org/reports/10Lauda16A-1.pdf.*

performance of at least one Hg CEMS at Hg levels below 1.0 microgram per cubic meter (μg/m³) down to approximately 0.1 μg/m³. Finally, there is no specific minimum data availability requirement for Hg CEMS (or any other CMS required under this final rule). This issue is discussed further below.

Comment: SO_2 CEMS: Although commenters were generally supportive of the ability to use SO_2 CEMS for units with FGD installed to demonstrate compliance with an alternate SO_2 emission limit instead of the HCl emission limit, there were some concerns with aspects of the proposal. Commenters requested that the SO_2 monitoring requirements rely on 40 CFR part 75 given that their sources were already meeting those requirements and that this rule not establish any new requirements, especially a fourth linearity level and the application of 7-day calibration error tests for units with low concentrations (where 40 CFR part 75 provides an exemption). Commenters were also concerned that the rule language only allows the option where the FGD is operated "at all times" which seems to imply that the option is not allowed if the source ever bypasses the FGD for start-up, shutdown, or malfunction reasons.

Response: After reviewing the comments and assessing the need for an additional calibration gas at the emissions limit, we have removed this requirement from the final rule while retaining the requirement for a linearity check even for SO_2 monitors with low span values (≤ 30 ppm). A source can already report linearity tests for these units within the context of the existing ECMPS reporting without triggering any critical errors. This test can be accommodated within the current framework without causing issues for 40 CFR part 75 reporting. The requirement for a 7-day calibration error test is removed. For the "at all times" language, we have clarified this in the final rule. The intent is that the FGD be operated during all routine boiler operations, and not operated intermittently, seasonally, or on some other non-fulltime basis.

Comment: HCl CEMS. In general, commenters argued that HCl CEMS do not have an approved performance specification and are not widely demonstrated as a proven technology. Those concerns were also mentioned for HF CEMS.

Response: We disagree with commenters' contention that continuous HCl monitoring is premature or not available for the measurement at the emission limits set in the final rule. HCl CEMS are being used on source categories such as municipal waste combustors and EGUs. We have reviewed HCl CEMS vendor technology claims and found sufficient capability to support this rule requirement. We are engaged with representative stakeholders to develop a generic performance specification for HCl CEMS scheduled for completion in time to be responsive to compliance with this rule.

The final rule provides several options for HCl and/or HF monitoring including:

(1) Using Fourier Transform Infrared (FTIR)-based HCl CEMS and/or HF CEMS complying with Appendix B to the rule which relies on PS 15,

(2) Seeking approval for an alternative HCl monitoring procedure through 40 CFR 63.7(f),

(3) Monitoring compliance continuously with the alternate SO_2 emission limit at coal-fired or other solid fuel affected facilities equipped with FGD technology for SO_2, and

(4) Quarterly reference method testing.

Including these options in the final rule provides flexibility to adopt CEMS monitoring options as the technology continues to mature and the new, non-technology-specific EPA performance specifications becomes available.

Comment: Bypass Stacks. Several commenters raised concerns about the technical feasibility of monitoring bypass stacks with a CEMS.

Response: We have modified the bypass stack monitoring requirements. Under 40 CFR part 75, we allow the use of a maximum potential concentration value for reporting when emissions are vented to a bypass stack. That approach works within the context of an emissions trading program, but is not appropriate when evaluating compliance with a specific emission limit. Thus, we have provided two other options. One is to monitor the bypass stack, consistent with the final rule. The other is to treat any hours of bypass stack emissions as periods of monitor downtime and hours of deviation from the monitoring requirements. Note that a source's units must continue to meet their 30-boiler operating day emissions limits during malfunction periods.

Comment: 40 CFR part 75 Issues. There were a number of general comments about the value of relying on 40 CFR part 75 requirements, including elements such as conditional data validation. The commenters generally agreed that the 40 CFR part 75 bias test and bias adjustment factor, and the 40 CFR part 75 substitute data provisions should not apply. Instead of substitute data, many commenters suggested that we needed to clarify the valid reasons for monitor downtime and establish an appropriate minimum data availability requirement.

Response: We have attempted to harmonize the CEMS requirements in this final rule with those under 40 CFR part 75 wherever appropriate. One of those examples is the inclusion of conditional data validation for Hg CEMS. We disagree that this final rule needs a minimum data availability requirement. We have not included any specific minimum data availability requirement for CEMS or other monitoring in this final rule nor do we provide a specific tool for data substitution. We believe that there are other provisions in the final rule to provide incentives to conduct monitoring in a manner consistent with good air pollution control practices and to provide data sufficient to demonstrate compliance with a relatively long-term (30-boiler operating day) emissions rate limit. We agree that data quality certainty associated with any calculated value decreases with the collection of less data such as would occur with extended periods of monitoring system downtime. Even so, we believe also that it is necessary and critical for compliance with the regulation that a source use all measured data collected during an averaging period to assess compliance regardless of any periods of missing data. Sources should not disqualify any data otherwise meeting required data quality requirements simply because there were data missing for other hours or days of the averaging period.

Instead of a minimum data availability threshold that would invalidate data collected for some averaging periods because one did not collect data for at least a specified percent of an averaging time, the final rule requires that a source report as deviations to the rule failure to collect data during required periods if these deviations are not covered by exceptions allowed in the final rule.

On the issue of applying a data substitution procedure to represent actual emissions or pollution control performance, we are not requiring data substitutions under this rule. We believe, however, that defensibility concerns make it incumbent on the source to collect and evaluate other information in accordance with 40 CFR section 63.6(f)(3) during periods of monitoring downtime to assure compliance with the applicable emissions limitations and standards.

We believe that enforcement authorities also can and should determine whether a source is meeting any monitoring system operating

requirements. Should the source or the enforcement authority be concerned about the representativeness of data such as during periods of missing data, either one may consider collecting information through other means (*e.g.*, supplemental emissions testing) to fill data gaps not only because such gaps are deviations from the rule but such gaps can lead to uncertainty about compliance status.

We further believe that the final rule provides sufficient means to ensure CMS performance and ongoing compliance without specifying an arbitrary numerical minimum data availability or data substitution requirement. We believe that specifying failure to collect required or otherwise excepted data as a deviation from the rule will provide the necessary incentive to collect data sufficient to demonstrate compliance with the limits in the final rule.

Comment: Recordkeeping. Several commenters opposed the requirements related to maintaining records on site and for 5 years.

Response: We believe the recordkeeping and retention requirements are consistent with other requirements already in place, specifically 40 CFR 63.10 (b).

In addition, the 5-year retention period is the general rule for all recordkeeping for all sources under the part 70 operating permits program. Given that the General Provisions for 40 CFR part 63 and part 70 already establish a 5-year retention period, we believe it is justified in using those precedents for the retention periods under this subpart. If we stayed silent on retention period in this subpart, the General Provisions would provide for the 5-year retention as would the part 70 requirements. Thus, this action does not establish any new retention requirements, but merely confirms that the existing retention requirements apply.

Comment: Electronic Reporting. In the proposed rule, we requested comment on using ECMPS for reporting under this rule, as well as other options including the ERT. Commenters generally supported the use of ECMPS, especially for CEMS data. Some commenters requested an additional rulemaking on the specific data elements to be collected. There were some concerns raised about the ERT given experience during the 2010 ICR process during the development of this rule.

Response: We recognize that emissions reporting for continuously measured pollutants (SO_2, NO_X, etc.) and for periodically measured pollutants (PM, HAP metals, etc.) have different data demands. We recognize that minor revisions of the ECMPS will fulfill our data needs for most continuously measured pollutants and we will make these modifications for receipt of the additional CEMS data. We also recognize the need for substantial modifications to the ECMPS to accommodate the data needs for periodically measured pollutants and certain CEMS data such as PM CEMS data and possibly HAP metals CEMS data. Although major modifications of the ECMPS would be required for periodic compliance tests by isokinetic and instrumental test methods (as well as certain types of CEMS), only minor revisions are required of the ERT to receive these tests. We are implementing the changes in the ERT that are required to provide the software tools to implement the delivery of these performance test data to us.

The electronic submission of compliance test reports to us through the Central Data Exchange (CDX) is not solely for the purpose of developing improved emissions factors as some commenters assert. Although populating WebFIRE will allow us to improve emissions factors, we intend to use data stored in WebFIRE as the primary location for compliance test reports for use by regulatory authorities. The electronic submission of compliance test reports is a continuation of our efforts to bring the submission and sharing of environmental data into the modern age. The storage of this compliance data in our WebFIRE provides a convenient location which is already used to store source test data.

As federal and state and local agencies' data systems mature, information provided through the ERT will be used to populate these data systems. We are currently upgrading the AIRS Facility System and expect to replace manually entered information with electronic population from the ERT. We are also working with several state and local agencies to adopt the use of the ERT for delivery of compliance test reports. The ERT is also much improved since the version used during the 2010 ICR process, and there is no expectation that the information to be reported under this final rule will be as extensive as some of the data reported for the 2010 ICR purposes.

We disagree that a separate and independent regulatory action is required to implement electronic reporting for selected regulated sources. Each of these regulatory actions for selected source categories provides ample notice and the opportunity for individuals to provide comment. We also disagree that the system to receive the compliance data must be operational prior to establishing the requirement for regulated sources to submit compliance data electronically. We are on track to have the capability to receive electronic compliance tests through our CDX in sufficient time to receive all utility source test reports required by this final rule.

We do plan a separate and independent regulatory action to implement electronic reporting for regulated entities which are covered by past and future rules. Although we have provided draft procedures for the development of emissions factors, that effort is an ancillary effort to the electronic delivery of compliance test reports. It is our intention to convert to the electronic delivery and storage of all air emissions compliance source test data. With this transition, we believe this valuable information will be more readily available not only for compliance purposes but also for a variety of other uses.

I. Emissions Averaging

Comment: In response to our request for comments on the suitability of emissions averaging and need for a discount factor, we received a range of suggestions, including requests for clarification regarding eligibility, points for and against the need for a discount factor, and suggestions to ease implementation.

Response: We are finalizing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for EGUs at the affected source that are within a single subcategory and that rely on emissions testing as the compliance demonstration method. See section VI of thie preamble for a fuller discussion.

J. LEE Criteria

Comment: A commenter supported the LEE provisions but believed one of the LEE eligibility criteria should set at 29.0 lb/year, rather than 22.0 lb/year. The commenter suggested 29.0 lb/year to be an equally reasonable cut point, especially since that value matches the low mass emitter Hg monitoring cutoff in CAMR and the low mass emitter Hg monitoring cutoff that several states have adopted, including Illinois, 35 Ill. Admin. Code section 225.240(a)(4). (*See, e.g.*, Colorado (5 Colo. Code Regs. section 1 00 1–8, Reg. No.6, part B, Section VIII.B.l0); Michigan (Mich. Admin. Code R. 336.2160); Montana (Mont. Admin. R. 17.8771(12))). Further, a LEE cutoff of 29.0 lb would eliminate conflicts and confusion with low mass emitter provisions in existing state Hg

programs and significantly reduce compliance costs and burdens for the additional qualifying units without adversely affecting compliance assurance with the EGU NESHAP Hg emission limits or materially increasing the number of potential qualifying LEEs. Given the many other costly burdens that the rule would impose, the benefit of LEE to a qualifying unit is not insignificant.

Response: The Agency reviewed the commenter's suggestions, and one of the LEE eligibility criteria in the rule has been revised from 22.0 to 29.0 lb of Hg per year. The Agency finds the result of consistency with existing state regulations outweighs the two percent difference in nationwide Hg mass emissions, from 5 percent to 7 percent, for LEE eligibility.

VIII. Background Information on the NSPS

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

New source performance standards implement CAA section 111(b), and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. Section 111 of the CAA requires that NSPS reflect the application of the best system of emissions reductions which (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. The level of control prescribed by CAA section 111 historically has been referred to as "Best Demonstrated Technology" or BDT. In order to better reflect that CAA section 111 was amended in 1990 to clarify that "best systems" may or may not be "technology," the EPA is now using the term "best system of emission reduction" or BSER. As was done previously in analyzing BDT, the EPA uses available information and considers the emission reductions and incremental costs for different systems available at reasonable cost. Then, the EPA determines the appropriate emission limits representative of BSER. 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.

B. What is the regulatory authority for the final rule?

The current standards for steam generating units are contained in the NSPS for EGUs (40 CFR part 60, subpart Da), industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db), and small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc).

The NSPS for EGUs (40 CFR part 60, subpart Da) were originally promulgated on June 11, 1979 (44 FR 33580) and apply to units capable of firing more than 73 megawatts (MW) (250 MMBtu/h) heat input of fossil fuel that commenced construction, reconstruction, or modification after September 18, 1978. The NSPS for EGUs also apply to industrial-commercial-institutional cogeneration units that sell more than 25 MW and more than one-third of their potential output capacity to any utility power distribution system. The most recent significant amendments to emission standards under 40 CFR part 60, subpart Da, were promulgated in 2006 (71 FR 9866) resulting in new PM, SO_2, and NOP_2 limitations for 40 CFR part 60, subpart Da units.

The NSPS for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db) apply to units for which construction, modification, or reconstruction commenced after June 19, 1984, that have a heat input capacity greater than 29 MW (100 MMBtu/h). Those standards were originally promulgated on November 25, 1986 (51 FR 42768) and also have been amended since the original promulgation to reflect changes in BSER for these sources.

The NSPS for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc) were originally promulgated on September 12, 1990 (55 FR 37674) and apply to units with a maximum heat input capacity greater than or equal to 2.9 MW (10 MMBtu/h) but less than 29 MW (100 MMBtu/h). Those standards apply to units that commenced construction, reconstruction, or modification after June 9, 1989.

IX. Summary of the Final NSPS

The final rule amends the emission standards for SO_2, NOP_2, and PM in 40 CFR part 60, subpart Da. Only those units that begin construction, modification, or reconstruction after May 3, 2011, will be affected by the final rule. Compliance with the emission limits of the final rule will be determined using testing, monitoring, and other compliance provisions similar to those set forth in the existing standards. In addition to the emissions limits contained in the final rule, we also are including several technical clarifications and corrections to existing provisions of the subparts.

A. What are the requirements for new EGUs (40 CFR part 60, subpart Da)?

The filterable PM emissions standard for new and reconstructed EGUs is 11 nanograms per joule (ng/J) (0.090 pound per megawatt hour (lb/MWh)) gross energy output regardless of the type of fuel burned. The PM emissions standard for modified EGUs is essentially equivalent to the existing requirements of 13 ng/J (0.015 lb/MWh) heat input regardless of the type of fuel burned. Compliance with this emission limit can be determined using testing, monitoring, and other compliance provisions similar to those for PM standards set forth in the existing rule. While not required, PM CEMS may be used as an alternative method to demonstrate continuous compliance and as an alternative to opacity and parameter monitoring requirements.

The SO_2 emission limit for new and reconstructed EGUs is 130 ng/J (1.0 lb/MWh) gross energy output or 97 percent reduction regardless of the type of fuel burned with one exception. The EPA neither proposed to amended the SO_2 standard for coal refuse-fired EGUs, not reopened the issue of whether coal refuse-fired EGUs is an appropriate subcategory, and, therefore, that emissions standard is unchanged. The SO_2 emission limit for modified EGUs burning any fuel is 180 ng/J (1.4 lb/MWh) gross energy output or 90 percent reduction. Compliance with the SO_2 emission limit is determined on a 30-boiler operating day rolling average basis using a CEMS to measure SO_2 emissions and following the compliance provisions in the proposed rule.

The NO_X emission limit for new and reconstructed EGUs is 88 ng/J (0.70 lb/MWh) gross energy output regardless of the type of fuel burned with one exception. The exception is that for new and reconstructed EGUs that burn over 75 percent coal refuse (by heat input), the NO_X emission limit is 110 ng/J (0.85 lb/MWh) gross energy output. The NO_X limit for modified EGUs is 140 ng/J (1.1 lb/MWh) gross energy output regardless of the type of fuel burned in the unit. Compliance with this emission limit is determined on a 30-boiler operating day rolling average basis using testing, monitoring, and other compliance provisions similar to those in the proposed rule.

As an alternative to the NO_X standard, owners/operators of new and reconstructed EGUs may elect to comply with a combined NO_X/CO standard of 140 ng/J (1.1 lb/MWh) with one exception. The exception is that for new

and reconstructed EGUs that burn over 75 percent coal refuse (by heat input) on an annual basis, the NO_X/CO emission limit is 160 ng/J (1.3 lb/MWh) gross energy output. Finally, owners/operators of modified EGUs may elect to comply with a combined NO_X/CO standard of 190 ng/J (1.5 lb/MWh).

B. Additional Amendments

See the Response to Comments document.

X. Summary of Significant Changes Since Proposal

A. Emission Limits

The proposal included a combined (filterable plus condensable) PM standard. The final standard is based only on filterable PM. No standard is being established for condensable PM. The rationale for this is set forth in the Response to Comments (RTC) document for this final rule (the NSPS Final Rule RTC).

The proposal requested comment on whether the final standard should include a stand-alone NO_X standard or a combined NO_X/CO standard. In response to comments we received and our own further evaluation of the situation, the final standard includes a stand-alone NO_X standard and an optional, but not required, combined NO_X/CO standard as an alternative to the amended NO_X standard. Again, our full rationale for this is set forth in the NSPS Final Rule RTC. The proposal also included a request for comment on whether the standard should be based on gross or net output. In response to comments we received and our own further evaluation of the situation, the final standards are based on an amended definition of gross output with an optional net output-based standard. This too is addressed more fully in the NSPS Final Rule RTC.

The proposal included alternate emission standards for commercial demonstration projects. Proposed commercial demonstrations included pressurized fluidized beds, multi-pollutant control technologies, and advanced combustion controls. The final rule includes the commercial demonstration permit exemption for pressurized fluidized beds and multi-pollutant control technologies, but not advanced combustion controls. Advanced combustion controls are applicable to existing facilities and the exemption is not necessary to further the development of the technology.

B. Requirements During Startup, Shutdown, and Malfunction

For startup and shutdown, the requirements for PM have changed since proposal. For periods of startup and shutdown, the EPA is finalizing work practice standards for PM in lieu of numeric emission limits. Emissions incurred during periods of startup and shutdown for PM are not used in demonstrations of compliance with the 30-boiler operating day rolling average period applicable for numeric emission standards.

XI. Public Comments and Responses to the Proposed NSPS

See the Response to Comments document.

XII. Impacts of the Final Rule

The EPA anticipates significant public health and environmental benefits from the rule as a direct result of the substantial reduction in the emissions of several pollutants, including SO_2, Hg, acid gases and fine particles and metals. For example, exposure to Hg can damage the developing nervous system, which can impair children's ability to think and learn, and fine particles can cause adverse cardiovascular effects. Further, reducing Hg deposition to ecosystems will benefit wildlife including fish, birds, and mammals. Fish and fish-eating birds, such as the common loon, and mammals suffer reproductive, survival, and behavioral impairments due to mercury exposure. These effects have also been observed in insect-eating and wading birds, including egrets and white ibis. Reductions of emissions targeted by this rule also will slow acidification and eutrophication of water bodies.

Additionally, the EPA anticipates significant non-health, non-ecological benefits from this rule. The fine particle and SO_2 emission reductions achieved by this rule will improve visibility, which is especially important for our national parks. Emissions reductions from this rule will also avoid an estimated $360 million (in $2007) of climate-related costs, such as agricultural productivity and property damage from increased flood risks.

A. What are the air impacts?

The EPA anticipates significant emission reductions under the final rule from coal-fired EGUs, which are of particular interest due to their share of total power sector emissions. In 2015, annual HCl emissions are projected to be reduced by 88 percent, Hg emissions reduced by 75 percent, and $PM_{2.5}$ emissions reduced by 19 percent from coal-fired EGUs greater than 25 MW. In addition, the EPA projects SO_2 emission reductions of 41 percent, and annual CO_2 reductions of 1 percent from coal-fired EGUs greater than 25 MW by 2015, relative to the base case. *See* Table 7.

TABLE 7—SUMMARY OF EMISSION REDUCTIONS FROM COAL-FIRED EGUS GREATER THAN 25 MW (TPY)

	SO_2 (million tons)	NO_X (million tons)	Mercury (tons)	HCl (thousand tons)	$PM_{2.5}$ (thousand tons)	CO_2 (million metric tonnes)
Base Case	3.3	1.7	27	45	270	1,906
MATS	1.9	1.7	7	6	218	1,882
Change	−1.4	0.0	−20	−40	−52	−23

Note: Numbers may not add due to rounding.

The reductions in this table do not account for reductions in other HAP which will occur as a result of this rule. For instance, the fine particulate reductions presented above only partly reflect reductions in many heavy metal particulates, and the HCl reductions above only partly reflect reductions of all acid gases. This rule will also result in additional HAP reductions from oil-fired EGUs, which are covered by the rule but are not included in the EPA's analysis of emission reductions.

B. What are the energy impacts?

The EPA projects that approximately 4.7 GW of coal-fired generation (less than 2 percent of all coal-fired capacity and 0.5 percent of total generation capacity in 2015) may be uneconomic to maintain and may be removed from operation by 2015. These units are predominantly smaller, less frequently used, and are dispersed throughout the country. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to

make further investments in these facilities and keep these units operational.

The final rule has other important energy market implications. Average nationwide retail electricity prices are projected to increase in the contiguous U.S. by 3.1 percent in 2015. The average delivered coal price is projected to increase by less than 2 percent in 2015 as a result of shifts within and across coal types. The EPA also projects that electric power sector-delivered natural gas prices will increase by between 0.3 and 0.6 percent over the 2015 to 2030 timeframe, on average, and that natural gas use for electricity generation will increase by less than 200 billion cubic feet (BCF) in 2015. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 10 million tons in 2015 from base case levels, which is about 1 percent of total coal produced for the electric power sector in that year.

C. What are the cost impacts?

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the base case and policy case in which the sector pursues pollution control approaches to meet the MATS emission standards. In simple terms, these costs are the resource costs of direct power industry expenditures to comply with the EPA's requirements.

The EPA projects that the annual incremental compliance cost of MATS is $9.6 billion in 2015 ($2007). The annualized incremental cost is the projected additional cost of complying with the rule in the year analyzed, and includes the amortized cost of capital investment and the ongoing costs of operating additional pollution controls, needed new capacity, shifts between or amongst various fuels, and other actions associated with compliance.

The total incremental compliance cost includes compliance costs modeled in IPM of $9.4 billion, costs modeled outside of IPM for oil-fired EGUs of $56 million, and monitoring, reporting, and recordkeeping costs of $158 million.

D. What are the economic impacts?

For this final rule, EPA analyzed the costs using the IPM. The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for a variety of HAP and other pollutants throughout the contiguous U.S. for the entire power system.

Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.*

The EPA performed a screening analysis for impacts on small entities by comparing compliance costs to sales/revenues (*e.g.*, sales and revenue tests). The EPA's analysis can be found in Chapter 7 of the RIA for this rule. The EPA has also prepared a Final Regulatory Flexibility Analysis (FRFA) that discusses alternative regulatory or policy options that minimize the rule's small entity impacts.

Although a stand-alone analysis of employment impacts is not included in a standard cost-benefit analysis, the current economic climate has led to heightened concerns about potential job impacts. Executive Order 13563 specifically states that our "regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and *job creation*" (emphasis added).

Under conditions of full employment, it is conventional to assume that regulations will merely shift jobs from one sector to another, without having a material effect on employment levels. Potential employment effects are of greater concern in the current economic climate, with high levels of employment, because of the risk that displaced workers may not find alternative jobs. In addition, regulations that result in firms hiring workers, in order to ensure compliance, may have a positive effect on employment.

During sustained periods of excess unemployment, the opportunity cost of labor required by regulated sectors to bring their facilities into compliance with an environmental regulation may be lower than it would be during a period of full employment (particularly if regulated industries employ otherwise idled labor to design, fabricate, or install the pollution control equipment required under this final rule). Consistent with EO 13563, the EPA includes estimates of job impacts associated with the final rule. In the electricity sector, the EPA estimates that the net employment effect will range from −15,000 to +30,000 jobs, with a central estimate of +8,000. The EPA also presents an estimate of short-term employment effects as a result of increased demand for pollution control equipment.

The results of this analysis, found in Chapter 6 of the RIA, indicate that the final rule has the potential to provide increases in short-term employment in the environmental industry, primarily driven by the high demand for new pollution control equipment. Overall, the results suggest that the final rule could support a net of roughly 46,000 job years[355] in direct employment impacts in 2015.

There are other employment effects that cannot be estimated quantitatively at this time. The employment gains related to the new pollution controls are likely to be tempered by some losses due to certain coal retirements. On the other hand, some of those workers who lose their jobs due to plant retirements could find alternative employment operating the replacement electricity generating equipment or new pollution controls at nearby units. Finally, job losses due to reduced coal demand may be offset by job gains due to increased natural gas demand, potentially resulting in a positive net change in employment due to fuel demand changes.

The basic approach to estimate these employment impacts involved using IPM projections from the final rule analysis, in particular the amount of existing coal-fired capacity that is projected to be retrofit with pollution control technologies. These data, along with data on labor and resource needs of new pollution controls and labor productivity from engineering studies and secondary sources, are used to estimate employment impacts for the pollution control industry in 2015. For more information, please refer to Chapter 6 and appendix 6B in the RIA.

The EPA relied on Morgenstern, *et al.*, (2002), to identify three economic mechanisms by which pollution abatement activities can influence jobs in the regulated sector separately from the short-term employment effects:

- Higher production costs raise market prices, higher prices reduce consumption, and employment within an industry falls ("demand effect");
- Pollution abatement activities require additional labor services to produce the same level of output ("cost effect"); and
- Post-regulation production technologies may be more or less labor intensive (i.e., more/less labor is required per dollar of output) ("factor-shift effect").

Using plant-level Census information between the years 1979 and 1991,

[355] Numbers of job years are not the same as numbers of individual jobs, but represents the amount of work that can be performed by the equivalent of one full-time individual for a year (or FTE). For example, 25 job years may be equivalent to five full-time workers for five years, 25 full-time workers for one year, or one full-time worker for 25 years.

Morgenstern,*et al.*, estimate the size of each effect for four polluting and regulated industries (petroleum, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million spent on pollution abatement results in a small net increase of 1.55 jobs; the estimated effect is not a statistically different from zero. As a result, the authors conclude that increases in pollution abatement expenditures may increase employment in the relevant sectors and do not necessarily cause economically significant employment changes. The conclusion is similar to that of Berman and Bui (2001) who found that increased air quality regulation in Los Angeles did not cause large employment changes.[356] For more information, please refer to Chapter 6 of the RIA for this final rule.[357]

In the directly affected sector, the EPA estimates that the net employment effect will range from −15,000 to +30,000 jobs, with a central estimate of +8,000. The ranges of job effects for the electricity sector, as calculated using the Morgenstern,*et al.*, approach are listed in Table 8.

TABLE 8—RANGE OF JOB EFFECTS FOR THE ELECTRICITY SECTOR

	Estimates using Morgenstern, *et al.*, (2001)			
	Demand effect	Cost effect	Factor shift effect	Net effect
Change in Full-Time Jobs per Million Dollars of Environmental Expenditure[a].	−3.56	2.42	2.68	1.55.
Standard Error	2.03	0.83	1.35	2.24.
EPA estimate for Final Rule[b]	−39,000 to +2,000	+4,000 to +21,000	+200 to +27,000	−15,000 to +30,000.

[a] Expressed in 1987 dollars. *See* footnote a from Table 6–2 of the RIA for inflation adjustment factor used in the analysis.
[b] According to the 2007 Economic Census, the electric power generation, transmission and distribution sector (NAICS 2211) had approximately 510,000 paid employees.

The EPA recognizes there may be other job effects that are not considered in the Morgenstern,*et al.*, study. Although EPA has considered some economy-wide changes, we do not have sufficient information to quantify other job effects associated with this rule.

E. What are the benefits of this final rule?

1. Benefits of Reducing HAP Emissions

a. Human Health and Environmental Effects Due to Exposure to MeHg. In this section, we provide a qualitative description of human health and environmental effects due to exposure to MeHg. The NAS Study (NRC, 2000) provides a thorough review of the effects of MeHg on human health. Many of the peer-reviewed articles cited in this section are publications originally cited in the NAS Study. In addition, the EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NAS in 2000.

b. Neurologic Effects of Exposure to MeHg. In its review of the literature, the NAS found neurodevelopmental effects to be the most sensitive and best documented endpoints and concluded that they are appropriate for establishing an RfD (NRC, 2000); in particular NAS supported the use of results from neurobehavioral or neuropsychological tests. The NAS Study (NRC, 2000) noted that studies in animals reported sensory effects as well as effects on brain development and memory functions and support the conclusions based on epidemiology studies. The NAS noted that their recommended neurodevelopmental endpoints for an RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: "The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school."

c. Cardiovascular Impacts of Exposure to MeHg. The NAS summarized data on cardiovascular effects available up to 2000. Based on these and other studies, the NAS Study concluded that "Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.*, neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals." The report also stated that "additional studies are needed to better characterize the effect of MeHg exposure on blood pressure and cardiovascular function at various stages of life."

Additional cardiovascular studies have been published since 2000. The EPA did not develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

d. Genotoxic Effects of Exposure to MeHg. The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS Study indicated that evidence that human exposure to MeHg causes genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajós River region in Brazil (Amorim*et al.*, 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes, as well as effects on chromosomes. Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those

[356] For alternative views in economic journals, see Henderson (1996) and Greenstone (2002).

[357] It should be noted that if more labor must be used to produce a given amount of output, then this implies a decrease in labor productivity. A decrease in labor productivity will cause a short-run aggregate supply curve to shift to the left, and businesses will produce less, all other things being equal.

seen in the populations studied in the Faroe Islands and Republic of Seychelles.

e. Immunotoxic Effects to Exposure to MeHg. Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response (ATSDR, 1999), evidence for immunotoxic effects of MeHg is limited (NRC, 2000).

f. Other Hg-Related Human Toxicity Data. Based on limited human and animal data, MeHg is classified as a "possible" human carcinogen by the International Agency for Research on Cancer (IARC, 1994) and in IRIS (USEPA, 2002). The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg exposure and specific types of cancer incidence (*e.g.,* acute leukemia and liver cancer) (NAS, 2000).

Some evidence of reproductive and renal toxicity in humans from MeHg exposure exists. However, overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

g. Ecological Effects of Hg. Deposition of Hg to watersheds can also have an impact on ecosystems and wildlife. Mercury contamination is present in all environmental media, with aquatic systems experiencing the greatest exposures due to bioaccumulation. Bioaccumulation refers to the net uptake of a contaminant from all possible pathways and includes the accumulation that may occur by direct exposure to contaminated media as well as uptake from food.

A review of the literature on effects of Hg on fish[358] reports results for numerous species including trout, bass (large and smallmouth), northern pike, carp, walleye, salmon, and others from laboratory and field studies. The effects of MeHg in fish are reproductive in nature. Although we cannot determine at this time whether these reproductive deficits are affecting fish populations across the U.S. it should be noted that it would seem reasonable that over time reproductive deficits would have an effect on populations.

Mercury also affects avian species. In previous reports[359] much of the focus has been on large piscivorous species, in particular the common loon. According to Evers,*et al.,* significant adverse effects from Hg on breeding loons have been found to occur, including behavioral (reduced nest-sitting), physiological (flight feather asymmetry) and reproductive (chicks fledged/territorial pair) effects and reduced survival.[360] Additionally, Evers, *et al.,* (*see* footnote 5), believe that the weight of evidence indicates that population-level effects occur in parts of Maine and New Hampshire, and potentially in broad areas of the loon's range.

Recently, attention has turned to other piscivorous species such as the white ibis and great snowy egret. These wading birds have a very wide diet including crayfish, crabs, snails, insects and frogs. White ibis have been observed to have decreased foraging efficiency[361] and have been shown to exhibit decreased reproductive success and altered pair behavior.[362] In egrets, Hg has been implicated in the decline of the species in south Florida,[363] and Hoffman[364] has shown that egrets exhibit liver and possibly kidney effects. Although ibises and egrets are most abundant in coastal areas and these studies were conducted in south Florida and Nevada, the ranges of ibises and egrets extend to a large portion of the U.S.

Insectivorous birds have also been shown to suffer adverse effects due to Hg exposure. Songbirds such as Bicknell's thrush, tree swallows, and the great tit have shown reduced reproduction, survival, and changes in singing behavior. Exposed tree swallows produced fewer fledglings,[365] had lower survival rates,[366] and had compromised immune competence.[367] The great tit has exhibited reduced singing behavior and smaller song repertoire in areas of high contamination.[368]

In mammals, adverse effects have been observed in mink and river otter, both fish eating species. For otter from Maine and Vermont, maximum concentrations of Hg in fur nearly equal or exceed a level associated with mortality and concentration in liver for mink in Massachusetts/Connecticut and the levels in fur from mink in Maine exceed concentrations associated with acute mortality.[369] Adverse sublethal effects may be associated with lower Hg concentrations and consequently may be more widespread than potential acute effects. These effects may include increased activity, poorer maze performance, abnormal startle reflex, and impaired escape and avoidance behavior.[370]

h. Methodology for Partial Hg Benefits Estimation. The EPA has conducted a national-scale analysis of the benefits to recreational anglers of avoided IQ loss related to reductions of Hg emissions

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[358] Crump, KL, and Trudeau, VL. Mercury-induced reproductive impairment in fish. Environmental Toxicology and Chemistry. Vol. 28, No. 5, 2009.

[359] U.S. Environmental Protection Agency (EPA). 1997. Mercury Study Report to Congress. Volume V: Health Effects of Mercury and Mercury Compounds. EPA–452/R–97–007. U.S. EPA Office of Air Quality Planning and Standards, and Office of Research and Development; U.S. Environmental Protection Agency (U.S. EPA). 2005. *Regulatory Impact Analysis of the Final Clean Air Mercury Rule.* Research Triangle Park, NC., March; EPA report no. EPA–452/R–05–003. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/mercury_ria_final.pdf.*

[360] Evers, DC, Savoy, LJ, DeSorbo, CR, Yates, DE, Hanson, W, Taylor, KM, Siegel, LS, Cooley, JH, Jr., Bank, MS, Major, A, Munney, K, Mower, BF, Vogel, HS, Schoch, N, Pokras, M, Goodale, MW, Fair, J. Adverse effects from environmental mercury loads on breeding common loons. Ecotoxicology. 17:69–81, 2008; Mitro, MG, Evers, DC, Meyer, MW, and Piper, WH. Common loon survival rates and mercury in New England and Wisconsin. Journal of Wildlife Management. 72(3): 665–673, 2008.

[361] Adams, EM, and Frederick, PC. Effects of methylmercury and spatial complexity on foraging behavior and foraging efficiency in juvenile white ibises (Eudocimus albus). Environmental Toxicology and Chemistry. Vol 27, No. 8, 2008.

[362] Frederick, P, and Jayasena, N. Altered pairing behavior and reproductive success in white ibises exposed to environmentally relevant concentrations of methylmercury. Proceedings of The Royal Society B. doi: 10–1098, 2010.

[363] Sepulveda, MS, Frederick, PC, Spalding, MG, and Williams, GE, Jr. Mercury contamination in free-ranging great egret nestlings (Ardea albus) from southern Florida, USA. Environmental Toxicology and Chemistry. Vol. 18, No. 5, 1999.

[364] Hoffman, DJ, Henny, CJ, Hill, EF, Grover, RA, Kaiser, JL, Stebbins, KR. Mercury and drought along the lower Carson River, Nevada: III. Effects on blood and organ biochemistry and histopathology of snowy egrets and black-crowned night-herons on Lahontan Reservoir, 2002–2006. Journal of Toxicology and Environmental Health, Part A. 72: 20, 1223–1241, 2009.

[365] Brasso, RL, and Cristol, DA. Effects of mercury exposure in the reproductive success of tree swallows (Tachycineta bicolor). Ecotoxicology. 17:133–141, 2008.

[366] Hallinger, KK, Cornell, KL, Brasso, RL, and Cristol, DA. Mercury exposure and survival in free-living tree swallows (Tachycineta bicolor). Ecotoxicology. Doi: 10.1007/s10646–010–0554–4, 2010.

[367] Hawley, DM, Hallinger, KK, Cristol, DA. Compromised immune competence in free-living tree swallows exposed to mercury. Ecotoxicology. 18:499–503, 2009.

[368] Gorissen, L, Snoeijs, T, Van Duyse, E, and Eens, M. Heavy metal pollution affects dawn singing behavior in a small passerine bird. Oecologia. 145: 540–509, 2005.

[369] Yates, DE, Mayack, DT, Munney, K, Evers DC, Major, A, Kaur, T, and Taylor, RJ. Mercury levels in mink (Mustela vison) and river otter (Lonra canadensis) from northeastern North America. Ecotoxicology. 14, 263–274, 2005.

[370] Scheuhammer, AM, Meyer MW, Sandheinrich, MB, and Murray, MW. Effects of environmental methylmercury on the health of wild birds, mammals, and fish. Ambio. Vol.36, No.1, 2007.

and subsequent deposition that will be achieved by this rule. Because the primary measurable health effect of concern—developmental neurological abnormalities in children—occurs as a result of in-utero exposures to Hg, the specific population of interest in this case is prenatally exposed children. To identify and estimate the size of this exposed population, the benefits analysis focused on pregnant women in freshwater recreational angler households. Estimating Hg exposures for this exposure pathway and population of interest requires three main components: (1) The size of the exposed population of interest (annual number of pregnant women in freshwater angler households during the year), (2) the average concentration of MeHg in noncommercial freshwater fish filets consumed, and (3) the average daily consumption rate of noncommercial freshwater fish. The Hg concentrations of fish in the waterbodies where the fish are caught are modeled using Mercury Maps to project the decline in concentrations due to the rule. To approximate the percentage of freshwater fishing trips (and exposed individuals) from each Census tract matched to each waterbody type, the EPA used state-level averages. These averages were calculated for each state, based on the portion of residents' freshwater fishing trips that are to each waterbody type, based on 2001 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation (FHWAR) data.

Data from the 1994 National Survey on Recreation and the Environment (NSRE) were used to approximate the percentage of freshwater fishing trips (and exposed individuals) matched to different distances from anglers' residential location.

To determine an appropriate daily fish consumption rate for the analysis, the EPA conducted an extensive review of existing literature characterizing self-caught freshwater fish consumption. Based on this review, it was decided that the ingestion rates for recreational freshwater fishers, specified as "recommended" in the EPA's "Environmental Exposure Factors Handbook" (EPA, 1997), represented the most appropriate values to use in this analysis.

Estimating the IQ decrements in children that result from mothers' prenatal ingestion of Hg from fish required two steps. First, based on the estimated average daily maternal ingestion rate, the expected Hg concentration in the hair of exposed pregnant women was estimated. Second, to estimate the expected IQ decrement in offspring, the following dose-response relationship was developed based on the summary findings reported in Axelrad *et al.*, (2007).

The valuation approach used to assess monetary losses due to IQ decrements is based on an approach applied in previous EPA analyses (EPA, 2008). The approach expresses the potential loss to an affected individual resulting from IQ decrements in terms of foregone future earnings (net of changes in education costs) for that individual.

The estimate for "Present Value of Lifetime Earnings" is derived using earnings and labor force participation rate data from the Bureau of Labor Statistics 2006 Current Population Survey. Estimates of the average effect of a 1-point increase in IQ on lifetime earnings range from a 1.76 percent increase (Schwartz, 1994) to a 2.379 percent increase (Salkever, 1995). The percentage increases in the two studies reflect both the direct impact of IQ on hourly wages and indirect effects on annual earnings as the result of additional schooling and increased labor force participation. The estimate for years of additional schooling is based on Schwartz (1994), who reports an increase of 0.131 years of schooling per IQ point.

In addition to this positive net effect on earnings, an increase in IQ is also assumed to have a positive effect on the amount of time spent in school and on associated costs. To incorporate (1) uncertainty regarding the size of the percentage change in future earnings and (2) different assumptions regarding the discount rate, the resulting value estimates for the average net loss per IQ point decrement are expressed as a range. Assuming a 3 percent discount rate, value IQ ranges from $8,013 (using the Schwartz estimates) to $11,859 (using the Salkever estimates) in increased earnings per year per 1-point IQ increase. With a 7 percent discount rate assumption, the value IQ estimates range from $893 to $1,958 in increased earnings per year per 1-point IQ increase.

The EPA analyzed the aggregate national IQ and present-value loss estimates for two base case and three emission control scenarios. The highest losses are estimated for the 2005 base case. For the population of prenatally exposed children included in the analysis (almost 240,000), Hg exposures under baseline conditions during the year 2005 are estimated to have resulted in more than 25,500 IQ points lost. Assuming a 3 percent discount rate, the present-year value of these losses ranges from $204.8 million to $292.5 million nationally.[371] These losses represent expected present value of declines in future net earnings over the entire lifetimes of the children who are prenatally exposed during the year 2005. With a 7 percent discount rate, the present-year value range is considerably lower: $22.8 million to $50.0 million.

For this rule, the EPA generated estimates of aggregate nationwide benefits associated with reductions in Hg exposures and resulting reductions in IQ losses. Most importantly, the benefits of the 2016 MATS scenario (relative to the 2016 base case) are estimated to range between $4 million and $6 million (assuming a 3 percent discount rate), because of an estimated 511 point reduction in IQ losses. The EPA recognizes that these calculated benefits are a small subset of the benefits of reducing Hg emissions.

2. Health and Welfare Co-Benefits

Emission controls installed to meet the requirements of this rule will generate co-benefits by reducing criteria pollutants including $PM_{2.5}$ and SO_2, as well as CO_2. For this rule, we were only able to estimate the mortality benefits of $PM_{2.5}$ reductions due to changes in emissions of SO_2 and direct $PM_{2.5}$ and climate benefits resulting from CO_2 reductions. Additional co-benefits may result from decreases in $PM_{2.5}$ morbidity impacts, decreases in sulfur deposition and direct health effects of SO_2, and improvements in visibility in national parks and wilderness areas. Total co-benefits may be higher than the partial estimates of co-benefits provided here. Our best estimate of the monetized health and climate co-benefits of this rule in 2016 at a 3 percent discount rate are $37 billion to $90 billion or $33 billion to $81 billion at a 7 percent discount rate (2007$). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower health co-benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[372]

a. Human Health Co-Benefits. To estimate the human health co-benefits of this rule, the EPA used benefit-per-ton

[371] Monetized benefits estimates are for an immediate change in MeHg levels in fish. If a lag in the response of MeHg levels in fish were assumed, the monetized benefits could be significantly lower, depending on the length of the lag and the discount rate used. As noted in the discussion of the Mercury Maps modeling, the relationship between deposition and fish tissue MeHg is proportional in equilibrium, but the Mercury Maps approach does not provide any information on the time lag of response.

[372] Roman, *et al.*, 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268–2274.

factors to quantify the changes in $PM_{2.5}$-related health impacts and monetized benefits based on changes in SO_2 and direct $PM_{2.5}$ emissions. These benefit-per-ton factors were based on an interim baseline and policy scenario for which full-scale ambient air quality modeling and air quality-based human health benefits assessments were performed. This general approach and methodology is laid out in Fann, *et al.*, (2009),[373] but for this rule the air quality modeling used a better spatial representation of the emission changes from EGUs. Using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. For more details on the creation of the benefit-per-ton factors and their application to emission reductions under this rule, please refer to the RIA for this rule in the docket.

Table 9 presents the estimates of reduced annual incidence of $PM_{2.5}$-related health effects in 2016 resulting from this rule. Table 10 presents the estimated annual monetary value of the reduced incidence of quantified health endpoints in 2016 resulting from this rule.

The reduction in premature fatalities each year accounts for between 93 and 97 percent of the estimated health co-benefits that were monetized.

TABLE 9—ESTIMATED REDUCTIONS IN INCIDENCE OF $PM_{2.5}$-RELATED HEALTH EFFECTS IN 2016 [a]

Health effect	Number of reduced cases
Adult Premature Mortality	
Pope *et al.*, (2002) (age >30)	4,200. (1,200 to 7,200).
Laden *et al.*, (2006) (age >25)	11,000. (5,000 to 17,000).
Infant Premature Mortality (<1 year)	20. (−22 to 61).
Chronic Bronchitis	2,800. (88 to 5,600).
Non-fatal heart attacks (age >18)	4,700. (1,200 to 8,300).
Hospital admissions—respiratory (all ages)	830. (330 to 1,300).
Hospital admissions—cardiovascular (age >18)	1,800. (1,200 to 2,200).
Emergency room visits for asthma (age <18)	3,100. (1,600 to 4,700).
Acute bronchitis (age 8–12)	6,300. (−1,400 to 14,000).
Lower respiratory symptoms (age 7–14)	80,000. (31,000 to 130,000).
Upper respiratory symptoms (asthmatics age 9–11)	60,000. (11,000 to 110,000).
Asthma exacerbation (asthmatics 6–18)	130,000. (4,500 to 450,000).
Lost work days (ages 18–65)	540,000. (460,000 to 620,000).
Minor restricted-activity days (ages 18–65)	3,200,000. (2,600,000 to 3,800,000).

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

TABLE 10—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS IN 2016 [a]

Health effect	Monetized benefits
Adult Premature Mortality	
Pope, *et al.*, (2002) (age >30):	
3% discount rate	$34. ($2.6 to $100).
7% discount rate	$30. ($2.4 to $92).
Laden, *et al.*, (2006) (age >25):	
3% discount rate	$87. ($7.5 to $250).
7% discount rate	$78. ($6.8 to $230).
Infant Premature Mortality (<1 year)	$0.2. ($−0.2 to $0.8).
Chronic Bronchitis	$1.4. ($0.1 to $6.4).
Non-fatal heart attacks (age >18):	

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

TABLE 10—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS IN 2016 [a]—Continued

Health effect	Monetized benefits
3% discount rate	$0.5. ($0.1 to $1.3).
7% discount rate	$0.4. ($0.1 to $1.0).
Hospital admissions—respiratory (all ages)	$0.01. ($0.01 to $0.02).
Hospital admissions—cardiovascular (age >18)	$0.03. (<$0.01 to $0.05).
Emergency room visits for asthma (age <18)	<$0.01.
Acute bronchitis (age 8–12)	<$0.01.
Lower respiratory symptoms (age 7–14)	<$0.01.
Upper respiratory symptoms (asthmatics age 9–11)	<$0.01.
Asthma exacerbation (asthmatics 6–18)	<$0.01.
Lost work days (ages 18–65)	$0.1. ($0.1 to $0.1).
Minor restricted-activity days (ages 18–65)	$0.2. ($0.1 to $0.3).
Monetized Health Co-Benefits	
Pope, *et al.*, (2002):	
3% discount rate	$36. ($2.8–$110).
7% discount rate	$33. ($2.5–$100).
Laden, *et al.*, (2006):	
3% discount rate	$89. ($7.7–$260).
7% discount rate	$80. ($6.9–$240).

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

It is important to note that the magnitude of the $PM_{2.5}$ co-benefits is largely driven by the concentration response function for premature mortality. Experts have advised the EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. We cite two key empirical studies, one based on the American Cancer Society cohort study [374] and the other based on the extended Six Cities cohort study.[375] The analyses upon which this rule is based were selected from the peer-reviewed scientific literature. We used up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects, or to assign economic values even to those health and environmental outcomes that can be quantified. The uncertainties in the underlying scientific and economics literature (that may result in overestimation or underestimation of the co-benefits) are discussed in detail in the RIA. Despite these uncertainties, we believe the benefit analysis for this rule provides a reasonable indication of the expected health co-benefits of the rulemaking in future years under a set of reasonable assumptions.

When characterizing uncertainty in the PM-mortality relationship, the EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, the EPA's 2009 Integrated Science Assessment for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship.

In the RIA accompanying this rulemaking, rather than segmenting out impacts predicted to be associated with levels above and below a "bright line" threshold, the EPA includes a "lowest measured level" (LML) analysis that illustrates the increasing uncertainty that characterizes exposure attributed to levels of $PM_{2.5}$ below the LML of each epidemiological study used to estimate $PM_{2.5}$-related premature death. Figures provided in the RIA show the distribution of baseline exposure to $PM_{2.5}$, as well as the lowest air quality levels measured in each of the epidemiology cohort studies. This information provides a context for considering the likely portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction in $PM_{2.5}$-related premature mortality diminishes as baseline concentrations of $PM_{2.5}$ are lowered.

Based on the modeled interim baseline which is approximately equivalent to the final baseline (*see* Appendix A of the RIA), 11 percent and 73 percent of the estimated avoided mortality impacts occur at or above an

[374] Pope *et al.*, 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." Journal of the American Medical Association. 287:1132–1141.

[375] Laden*et al.*, 2006. "Reduction in Fine Particulate Air Pollution and Mortality." American Journal of Respiratory and Critical Care Medicine. 173:667–672.

annual mean $PM_{2.5}$ level of 10 μg/m3 (the LML of the Ladenet *al.*, 2006 study)or 7.5 μg/m3 (the LML of the Pope,*et al.*, 2002 study), respectively. Although the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, the EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations. A large fraction of the $PM_{2.5}$-related benefits occur below the level of the National Ambient Air Quality Standard (NAAQS) for $PM_{2.5}$ at 15 μg/m3, which was set in 2006. It is important to emphasize that NAAQS are not set at a level of zero risk. Instead, the NAAQS reflect the level determined by the Administrator to be protective of public health within an adequate margin of safety, taking into consideration effects on susceptible populations. While benefits occurring below the standard may be less certain than those occurring above the standard, EPA considers them to be legitimate components of the total benefits estimate.

It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Benefits are shown as a range from Pope, *et al.*, (2002), to Laden, *et al.*, (2006). These studies assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between directly-emitted particles (carbonaceous and crustal particles) and SO_2 emissions that form sulfate particles, based on the location of emission changes and magnitude of population exposure changes. Regardless, however, the assumption that all fine particles are equally potent in causing premature mortality adds uncertainty to the benefits estimate.

b. Non-Climate Welfare Co-Benefits. Emission controls installed to comply with the requirements specified in this rule will also generate co-benefits by improving visibility. We anticipate that improvements in visibility in Class I areas as well as residential areas where people live, work, and recreate could be substantial. Because full-scale air quality modeling was not performed for this rule, we are unable to quantify these visibility co-benefits for this rule. However, the estimated value of visibility benefits calculated from the modeled interim baseline and policy scenario was $1.1 billion (in 2007$). These visibility benefits are not included in the total co-benefits estimate of the final policy scenario used as a basis for this final rule. The distribution of emission reductions did not change substantially in the visibility regions studied, therefore visibility benefits of the final policy scenario are likely to be of a similar magnitude.

Ecosystem and other welfare effects include reduced acidification and, in the case of NO_X, eutrophication of water bodies; possible reduced nitrate contamination of drinking water; ozone vegetation damage; a reduction in the role of sulfate in Hg methylation; and reduced acid and particulate deposition that causes damages to cultural monuments, as well as soiling and other materials damage. To illustrate the important nature of benefit categories the EPA is currently unable to monetize, we discuss the potential public welfare and environmental impacts related to reductions in emissions required by this rule in the RIA, including reduced visibility impairment, reduced effects from acid deposition, reduced effects from nutrient enrichment, and reduced vegetation effects from ambient exposure to SO_2 and NO_2.

c. Climate co-benefits. This rule is expected to reduce CO_2 emissions from the electricity sector. The EPA has assigned a dollar value to reductions in CO_2 emissions using recent estimates of the "social cost of carbon" (SCC). The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year or the per metric ton benefit estimate relating to decreases in CO_2 emissions. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damage from increased flood risk, and the value of ecosystem services due to climate change.

The SCC estimates used in this analysis were developed through an interagency process that included the EPA and other executive branch entities, and that concluded in February 2010. We first used these SCC estimates in the benefits analysis for the final joint EPA/DOT Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; see the rule's preamble for discussion about application of the SCC (75 FR 25324; May 7, 2010). The SCC Technical Support Document (SCC TSD) provides a complete discussion of the methods used to develop these SCC estimates.[376]

The interagency group selected four SCC values for use in regulatory analyses, which we have applied in this analysis: $5.9, $24.3, $39, and $74.4 per metric ton of CO_2 emissions in 2016, in 2007 dollars. The first three values are based on the average SCC from three integrated assessment models, at discount rates of 5, 3, and 2.5 percent, respectively. Social cost of carbon values at several discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the SCC from all three values at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the extremes of the SCC distribution. Low probability, high impact events are incorporated into all of the SCC values through explicit consideration of their effects in two of the three values as well as the use of a probability density function for equilibrium climate sensitivity. Treating climate sensitivity probabilistically results in more high temperature outcomes, which in turn leads to higher projections of damages.

Applying the global SCC estimates using a 3 percent discount rate, we estimate the value of the climate related benefits of this rule in 2016 is $360 million (2007$), as shown in Table 11. See the RIA for more detail on the methodology used to calculate these benefits and additional estimates of climate benefits using different discount rates and the 95th percentile of the 3 percent discount rate SCC. Important limitations and uncertainties of the SCC approach are also described in the RIA.

[376] Docket ID EPA–HQ–OAR–2009–0472–114577, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at *http://epa.gov/otaq/climate/regulations.htm.*

TABLE 11—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS AND CLIMATE BENEFITS IN 2016[a]

Effect	Monetized benefits
Monetized Health Co-Benefits	
Pope, *et al.*, (2002):	
3% discount rate	$36 ($2.8–$110)
7% discount rate	$33 ($2.5–$100)
Laden, *et al.*, (2006):	
3% discount rate	$89 ($7.7–$260)
7% discount rate	$80 ($6.9–$240)
Climate-related Co-Benefits (3% discount rate)	$0.36
Monetized Total Co-Benefits	
Pope, *et al.*, (2002):	
3% discount rate	$37 ($3.2–$110)
7% discount rate	$33 ($2.9–$100)
Laden, *et al.*, (2006):	
3% discount rate	$90 ($8.0–$260)
7% discount rate	$81 ($7.3–$240)

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

Our best estimate for the monetized total health and climate co-benefits of this rule in 2016 at a 3 percent discount rate is between $37 billion and $90 billion or between $33 billion and $81 billion (2007$) at a 7 percent discount rate. These estimates account for the quantified health and climate benefits described in Table 11.

XIII. Statutory and Executive Order Reviews

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

Under EO 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 or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. Accordingly, the EPA submitted this action to the OMB for review under Executive Orders 12866 and 13563 and any changes in response to OMB recommendations have been documented in the docket for this action. For more information on the costs and benefits for this rule, please refer to Table 2 of this preamble.

When estimating the human health benefits and compliance costs in Table 2 of this preamble, the EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. The EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of this rulemaking. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. In doing what is laid out above in this paragraph, the EPA adheres to EO 13563, "Improving Regulation and Regulatory Review," (76 FR 3821; January 18, 2011), which is a supplement to EO 12866.

In addition to estimating costs and benefits, EO 13563 focuses on the importance of a "regulatory system [that] * * * promote[s] predictability and reduce[s] uncertainty" and that "identify[ies] and use[s] the best, most innovative, and least burdensome tools for achieving regulatory ends." In addition, EO 13563 states that "[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation." We recognize that the utility sector faces a variety of requirements, including ones under CAA section 110(a)(2)(D) dealing with the interstate transport of emissions contributing to ozone and PM air quality problems, with coal combustion wastes, and with the implementation of CWA section 316(b). In developing today's final rule, the EPA recognizes that it needs to approach these rulemakings in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that underlie the rulemakings.

A summary of the monetized costs, benefits, and net benefits for the final rule at discount rates of 3 percent and 7 percent is in Table 2 of this preamble. For more information on the analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the OMB under the Paperwork Reduction Act, 44

U.S.C. 3501 et seq. The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 2137.06.

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

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

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

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

For this reason, we estimate no more than two such occurrences for all sources subject to 40 CFR part 63, subpart UUUUU over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual monitoring, reporting, and record-keeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $207.6 million. This includes 700,296 labor hours per year at a total labor cost of $49.1 million per year, annualized capital costs of $81.9 million, and annual operating and maintenance costs of $76.5 million. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications, and recordkeeping. All burden estimates are in 2007 dollars and represent the most cost effective monitoring approach for affected facilities. Burden is defined at 5 CFR 1320.3(b).

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for our 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, as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that 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 today's rule on small entities, small entity is defined as: (1) A small business that is an electric utility producing 4 billion kilowatt-hours or less as defined by NAICS codes 221122 (fossil fuel-fired electric utility steam generating units) and 921150 (fossil fuel-fired electric utility steam generating units in Indian country); (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.

Pursuant to RFA section 603, the EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel to obtain advice

and recommendations of representatives of the regulated small entities. A detailed discussion of the Panel's advice and recommendations is found in the Panel Report (EPA–HQ–OAR–2009–0234–2921). A summary of the Panel's recommendations is presented at 76 FR 24975.

As required by RFA section 604, we also prepared a final regulatory flexibility analysis (FRFA) for the final rule. The FRFA addresses the issues raised by public comments on the IRFA, which was part of the proposal of this rule. The FRFA is summarized below and in the RIA.

1. Reasons Why Action Is Being Taken

In 2000, the EPA made a finding that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and listed EGUs pursuant to CAA section 112(c). On March 29, 2005 (70 FR 15994), the EPA published a final rule (2005 Action) that removed EGUs from the list of sources for which regulation under CAA section 112 was required. That rule was published in conjunction with a rule requiring reductions in emissions of Hg from EGUs pursuant to CAA section 111, i.e., CAMR, May 18, 2005, 70 FR 28606). The 2005 Action was vacated on February 8, 2008, by the U.S. Court of Appeals for the District of Columbia Circuit. As a result of that vacatur, CAMR was also vacated and EGUs remain on the list of sources that must be regulated under CAA section 112. This action provides the EPA's final NESHAP and NSPS for EGUs.

2. Statement of Objectives and Legal Basis for Final Rules

The MATS will protect air quality and promote public health by reducing emissions of HAP. In the December 2000 regulatory determination, the EPA made a finding that it was appropriate and necessary to regulate EGUs under CAA section 112. The February 2008 vacatur of the 2005 Action reverted the status of the rule to the December 2000 regulatory determination. Section 112(n)(1)(A) of the CAA and the 2000 determination do not differentiate between EGUs located at major versus area sources of HAP. Thus, the NESHAP for EGUs will regulate units at both major and area sources. Major sources of HAP are those that have the potential to emit at least 10 tons per year (tpy) of any one HAP or at least 25 tpy of any combination of HAP. Area sources are any stationary sources of HAP that are not major sources.

3. Summary of Issues Raised During the Public Comment Process on the IRFA

The EPA received a number of comments related to the Regulatory Flexibility Act during the public comment process. A consolidated version of the comments received is reproduced below. These comments can also be found in their entirety in the response to comment document in the docket.

Comment: Several commenters expressed concern with the SBAR panel. Some believe Small Entity Representatives (SERs) were not provided with regulatory alternatives including descriptions of significant regulatory options, differing timetables, or simplifications of compliance and reporting requirements, and subsequently were not presented with an opportunity to respond. One commenter believes the EPA's formal SBAR Panel notification and subsequent information provided by the EPA to the Panel did not include information on the potential impacts of the rule as required by CAA section 609(b)(1). Additional commenters suggested that the EPA's rulemaking schedule put pressure on the SBAR Panel through the abbreviated preparation for the Panel. Commenters also expressed concerns that the EPA did not provide participants more than cursory background information on which to base their comments. One commenter stated that the EPA did not provide deliberative materials, including draft proposed rules or discussions of regulatory alternatives, to the SBAR Panel members. One commenter stated the SBAR Panel Report does not meet the statutory obligation to recommend less burdensome alternatives. The commenter suggested the EPA panel members declined to make recommendations that went further than consideration or investigation of broad regulatory alternatives, with the exception of those recommendations in which the EPA rejected alternative interpretations of the CAA section 112 and relevant court cases. Two stated that the EPA did not respond to the concerns of the small business community, the SBA, or OMB, ignoring concerns expressed by the SER panelists. One commenter believes the EPA failed to convene required meetings and hearings with affected parties as required by law for small business entities. One commenter stated that the SERs' input is very important because more than 90 percent of public power utility systems meet the definition and qualify as small businesses under the SBREFA.

Response: The RFA requires that SBAR Panels collect advice and recommendations from SERs on the issues related to:

—The number and description of the small entities to which the proposed rule will apply;
—The projected reporting, recordkeeping and other compliance requirements of the proposed rule;
—Duplication, overlap or conflict between the proposed rule and other federal rules; and
—Alternatives to the proposed rule that accomplish the stated statutory objectives and minimize any significant economic impact on small entities.

The RFA does not require a covered agency to create or assemble information for SERs or for the government panel members. Although CAA section 609(b)(4) requires that the government Panel members review any material the covered agency has prepared in connection with the RFA, the law does not prescribe the materials to be reviewed. The EPA's policy, as reflected in its RFA guidance, is to provide as much information as possible, given time and resource constraints, to enable an informed Panel discussion. In this rulemaking, because of a court-ordered deadline, the EPA was unable to hold a pre-panel meeting but still provided SERs with the information available at the time, held a standard Panel Outreach meeting to collect verbal advice and recommendations from SERs, and provided the standard 14-day written comment period to SERs. The EPA received substantial input from the SERs, and the Panel report describes recommendations made by the Panel on measures the Administrator should consider that would minimize the economic impact of the proposed rule on small entities. The EPA complied with the RFA. In addition, we met with representatives of small businesses, small rural cooperatives, and small governments a number of times during the regulatory development process to discuss their issues and concerns regarding the proposed MATS rule for EGUs.

Comment: One commenter requested that the EPA work with utilities such that new regulations are as flexible and cost efficient as possible.

Response: In developing the final rule, the EPA has considered all information provided prior to, as well as in response to, the proposed rule. The EPA has endeavored to make the final regulations flexible and cost-efficient while adhering to the requirements of

the CAA. The final rule includes a number of flexibilities, such as those related to monitoring requirements, that will lower costs and simplify compliance for small businesses and local governments.

Comment: One commenter was concerned about the ability of small entities or nonprofit utilities such as those owned and/or operated by rural electric co-op utilities, and municipal utilities to comply with the proposed standards within 3 years. The commenter believes that the EPA disregarded the SER panelists who explained that under these current economic conditions they have constraints on their ability to raise capital for the construction of control projects and to acquire the necessary resources in order to meet a 3-year compliance deadline. Two commenters expressed concern that smaller utilities and those in rural areas will be unable to get vendors to respond to their requests for proposals, because they will be able to make more money serving larger utilities.

Response: The preamble to the proposed rule (76 FR 25054; May 3, 2011) provides a detailed discussion of how the EPA determined compliance times for the proposed (and final) rule. The EPA has provided pursuant to CAA section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls. *See* CAA section 112(i)(3)(B). If the situation described by commenters (*i.e.*, where small entities or nonprofit utilities constraints on ability to raise capital for construction of control projects and to acquire necessary resources) results in the source needing additional time to install controls, they would be in a position to request the 1-year extension.

Comment: Several commenters believe the EPA did not adequately consider the disproportionately large impact on smaller generating units. The commenters note the diseconomies in scale for pollution controls for such units. One commenter noted the rule will create a more serious compliance hurdle for small communities that depend on coal-fired generation to meet their base load demand. The commenter notes that by not subcategorizing units, the EPA is dictating a fuel switch due to the disproportionately high cost on small communities. The other commenter believes the MACT and NSPS standards are unachievable by going too far without really considering the impacts on small municipal units, as public power is critical to communities, jobs, economic viability and electric reliability. A generating and transmissions electric cooperative which qualifies as a small entity believes the rule will ultimately result in increased electricity costs to its members and will negatively impact the economies of the primarily rural areas that they serve. Another commenter believes there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units, particularly given the current market situation and applicable equitable factors. The commenter suggests both the EPA's and SBA's analyses focus exclusively on the effects on entities causing HAP emissions and primarily on those operating obsolete EGUs, and fail to consider either impacts on downwind businesses and governments or the positive impacts on small entities and governments owning and operating competing, clean and modern EGUs.

Response: The EPA disagrees with the commenters' belief that the impacts on smaller generating units were not adequately considered when developing the rule. The EPA determined the number of potentially impacted small entities and assessed the potential impact of the proposed action on small entities, including municipal units. A similar assessment was conducted in support of the final action. Specifically, the EPA estimated the incremental net annualized compliance cost, which is a function of the change in capital and operating costs, fuel costs, and change in revenue. The projected compliance cost was considered relative to the projected revenue from generation. Thus, the EPA's analysis accounts not only for the additional costs these entities face resulting from compliance, but also the impact of higher electricity prices. The EPA evaluated suggestions from SERs, including subcategorization recommendations. In the preamble to the proposed rule, the EPA explains that, normally, any basis for subcategorizing must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not see a distinction between emissions from smaller generating units versus larger units. The EPA acknowledges the comment that there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units.

Comment: One commenter notes that the EPA recognizes LEEs in the rule such that they should receive less onerous monitoring requirements; however, the EPA does not recognize that small and LEEs also need and merit more flexible and achievable pollution control requirements. The commenter notes that the capital costs for emissions control at small utility units is disproportionately high due to inefficiencies in Hg removal, space constraints for control technology retrofits, and the fact that small units have fewer rate base customers across which to spread these costs. The commenter cites the Michigan Department of Environmental Quality report titled "Michigan's Mercury Electric Utility Workgroup, Final Report on Mercury Emissions from Coal-Fired Power Plants," (June 2005). The commenter notes that the EPA has addressed such concerns previously, citing the RIA for the 1997 8-hour ozone standard. The commenter also suggests smaller utility systems generally have less capital to invest in pollution control than larger, investor-owned systems, due to statutory inability to borrow from the private capital markets, statutory debt ceilings, limited bonding capacity, borrowing limitations related to fiscal strain posed by other, non-environmental factors, and other limitations.

Response: The EPA acknowledges that the rule contains reduced monitoring requirements for existing units that qualify as LEEs. Although the EPA does not believe that reduced pollution control requirements are warranted for LEEs, including small entity LEEs, we believe that flexible and achievable pollution control requirements are promoted through alternative standards, alternative compliance options, and emissions averaging as a means of demonstrating compliance with the standards for existing EGUs.

Comment: One commenter believes that the EPA should develop more limited monitoring requirements for small EGUs. The commenter notes small entities do not possess the monetary resources, manpower, or technical expertise needed to operate cutting-edge monitoring techniques such as Hg CEMS and PM CEMS. The commenter notes the EPA could have identified monitoring alternatives to the SER panel for consideration.

Response: The EPA provided monitoring alternatives to using PM CEMS, HCl CEMS, and Hg CEMS in its proposed standards and in this final rule. The continuous compliance alternatives are available to all affected sources, including small entities. As alternatives to the use of PM CEMS and HCl CEMS, sources are allowed to

conduct additional performance testing. Sorbent trap monitoring is allowed in lieu of Hg CEMS.

Comment: Several commenters believe the EPA has not sufficiently complied with the requirements of the RFA or adequately considered the impact this rulemaking would have on small entities. One commenter believes the EPA has not engaged in meaningful outreach and consultation with small entities and therefore recommends that the EPA seek to revise the court-ordered deadlines to which this rulemaking is subject, re-convene the SBAR panel, prepare a new initial regulatory flexibility analysis (IRFA), and issue it for additional public comment prior to final rulemaking. The commenter believes the IRFA does not sufficiently consider impacts on small entities as identified in the SBAR Panel Report. The commenter believes it is not apparent that the EPA considered the recommendations of the Panel. The commenter believes the description of significant alternatives in the IRFA is almost entirely quoted from the SBAR Panel Report, which the commenter does not believe is an adequate substitute for the EPA's own analysis of alternatives. The commenter also notes the EPA does not discuss the potential impacts of its decisions on small entities or the impacts of possible flexibilities. Where the EPA does consider regulatory alternatives in principle, the commenter believes it does not provide sufficient support for its decisions to understand on what basis the EPA rejected alternatives that may or may not have reduced burden on small entities while meeting the stated objectives of the rule. Additionally, the commenter notes that the EPA did not evaluate the economic or environmental impacts of significant alternatives to the proposed rule. One commenter believes that the EPA's stated reasons for declining to specify or analyze an area source standard are inadequate under the RFA. The commenter believes the EPA must give serious consideration to regulatory alternatives that accomplish the stated objectives of the CAA while minimizing any significant economic impacts on small entities and that the EPA has a duty to specify and analyze this option or to more clearly state its policy reasons for excluding serious consideration of a separate standard for area sources. A commenter believes the EPA did not fully consider the subcategorization of sources such as boilers designed to burn lignite coals versus other fossil fuels, especially in regard to non-mercury metal and acid gas emissions. The commenter references the SBAR Panel Report suggestion provided in the preamble of the proposed rule that the EPA consider developing an area source vs. major source distinction for the source category and the EPA's response. Another commenter is concerned that the recommendations made by the SER participants were ignored and not discussed in the rulemaking. Specifically, the commenter notes the EPA did not discuss subcategorizing by age, type of plant, fuel, physical space constraints or useful anticipated life of the plant. Nor did the EPA establish GACT for smaller emitters to alleviate regulatory costs and operational difficulties. A commenter believes it is likely that different numerical or work practice standards are appropriate for area sources of HAP.

Response: The EPA disagrees with one commenter's assertion that the agency has not complied with the requirements of the RFA. The EPA complied with both the letter and spirit of the RFA, notwithstanding the constraints of the court-ordered deadline. For example, the EPA notified the Chief Counsel for Advocacy of the SBA of its intent to convene a Panel; compiled a list of SERs for the Panel to consult with; and convened the Panel. The Panel met with SERs to collect their advice and recommendations; reviewed the EPA materials; and drafted a report of Panel findings. The EPA further disagrees with the commenter's assertion that the EPA's IRFA does not sufficiently consider impacts on small entities. The EPA's IRFA, which is included in chapter 10 of the RIA for the proposed rule, addresses the statutorily required elements of an IRFA, such as the economic impact of the proposed rule on small entities and the Panel's findings.

The EPA disagrees with the comment that recommendations made by the SERs were not considered or discussed in the proposed rulemaking such as recommendations regarding subcategorization and separate GACT standards for area sources. The preamble to the proposed standards includes a detailed discussion of how the EPA determined which subcategories and sources would be regulated (76 FR 25036–25037; May 3, 2011). In that discussion, the EPA explains the rationale for its proposed subcategories based on five unit design types. In addition, the EPA acknowledges the subcategorization suggestions from the SERs and explains its reasons for not subcategorizing on those bases. The preamble to the proposed standards also includes a discussion of the SERs' suggestion that area source EGUs be distinguished from major-source EGUs and the EPA's reasons for not making that distinction (76 FR 25020–25021; May 3, 2011).

The EPA also disagrees with the suggestion that the Agency pursue an extension of the timeline for final rulemaking such that the SBAR Panel can be reconvened and a new IRFA can be prepared and released for public comment prior to the final rulemaking. The EPA entered into a Consent Decree to resolve litigation alleging that the EPA failed to perform a non-discretionary duty to promulgate CAA section 112(d) standards for EGUs. *See American Nurses Ass'n* v. *EPA*, 08–2198 (D.D.C.). That Decree required the EPA to sign the final MATS rule by November 16, 2011, unless the agency sought to extend the deadline consistent with the requirements of the modification provision of the Consent Decree. The EPA and Plaintiffs stipulated to a 30-day extension consistent with the modification provisions of the Consent Decree and the rule must be signed no later than December 16, 2011. If plaintiffs in the *American Nurses* litigation objected to an additional extension request, which we believe would have been likely, the Agency would have had to file a motion with the Court seeking an extension of the deadline. Consistent with governing case law, the Agency would have been required to demonstrate in its motion for extension that it was impossible to finalize the rule by the deadline provided in the Consent Decree. *See Sierra Club* v. *Jackson*, Civil Action No. 01–1537 (D.D.C.) (Opinion of the Court denying EPA's motion to extend a consent decree deadline). The EPA negotiated a 30-day extension and was able to complete the rule by December 16, 2011; accordingly, the Agency had no basis for seeking a further extension of time.

A detailed description of the changes made to the rule since proposal, including those made as a result of feedback received during the public comment process can be found in sections VI (NESHAP) and X (NSPS) of this preamble. Changes explained in the identified sections include those related to applicability; subcategorization; work practices; periods of startup, shutdown, and malfunction; initial testing and compliance; continuous compliance; and notification, recordkeeping, and reporting.

4. Description and Estimate of the Affected Small Entities

For the purposes of assessing the impacts of MATS on small entities, a small entity is defined as:

(1) A small business according to the Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. The range of small business size standards for electric utilities is 4 billion kilowatt hours (kWh) of production or less;

(2) A small government jurisdiction that is a government of a city, county, town, 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.

The EPA examined the potential economic impacts to small entities associated with this rulemaking based on assumptions of how the affected entities will install control technologies in compliance with MATS. This analysis does not examine potential indirect economic impacts associated with this rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households.

The EPA used Velocity Suite's Ventyx data as a basis for identifying plant ownership and compiling the list of potentially affected small entities. The Ventyx dataset contains detailed ownership and corporate affiliation information. The analysis focused only on those EGUs affected by the rule, which includes units burning coal, oil, petroleum coke, or coal refuse as the primary fuel, and excludes any combustion turbine units or EGUs burning natural gas. Also, because the rule does not affect combustion units with an equivalent electricity generating capacity up to 25 MW, small entities that do not own at least one combustion unit with a capacity greater than 25 MW were removed from the dataset. For the affected units remaining, boiler and generator capacity, heat input, generation, and emissions data were aggregated by owner and then by parent company. Entities with more than 4 billion kWh of annual electricity generation were removed from the list, as were municipal owned entities with a population greater than 50,000. For cooperatives, investor owned utilities, and subdivisions that generate less than 4 billion kWh of electricity annually but which may be part of a large entity, additional research on power sales, operating revenues, and other business activities was performed to make a final determination regarding size. Finally, small entities for which the IPM does not project generation in 2015 in the base case were omitted from the analysis because they are not projected to be operating and, thus, are not projected to face the costs of compliance with the rule. After omitting entities for the reasons above, the EPA identified a total of 82 potentially affected small entities that are affiliated with 102 EGUs.

5. Compliance Cost Impacts

The number of potentially affected small entities by ownership type and potential impacts of MATS are presented in Chapter 7 of the RIA and summarized here. The EPA estimated the annualized net compliance cost to small entities to be approximately $106 million in 2015 (2007$).

The EPA assessed the economic and financial impacts of the final rule using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent. Of the 82 small entities identified, The EPA's analysis shows 40 entities may experience compliance costs greater than 1 percent of base generation revenues in 2015, and 35 may experience compliance costs greater than 3 percent of base revenues. Also, all generating capacity at 3 small entities is projected to be uneconomic to maintain. In this analysis, the cost of withdrawing a unit as uneconomic is estimated as the base case profit that is forgone by not operating under the policy case. Because 35 of the 82 total units, or more than 40 percent, are estimated to incur compliance cost greater than 3 percent of base revenues, the EPA has concluded that it cannot certify that there will be no significant economic impact on a substantial number of small entities (SISNOSE) for this rule. Results for small entities discussed here do not account for the reality that electricity markets are regulated in parts of the country. Entities operating in regulated or cost-of-service markets should be able to recover all of their costs of compliance through rate adjustments.

Note that the estimated costs for small entities are significantly lower than those estimated by the EPA for the MATS proposal (which were $379 million). This is driven by a small group of units (less than 6 percent) which were projected to be uneconomic to operate under the proposal (and hence incurred lost profits due to lost electricity revenues), but are now projected to continue their operations under MATS. In addition, the EPA's modeling indicates one unit that would have operated at a low capacity factor under the base case would find it economical to increase its generation significantly under MATS to meet electricity demand in its region. Excluding this unit, the total cost impacts across all entities would be roughly $175 million. Changes in compliance behavior for this small group of units, in particular the one unit which operates at a higher capacity factor, has a substantial impact on total costs as their increased generation revenues offsets a large portion of the compliance costs.

The most significant components of incremental costs to these entities are changes in electricity revenues, followed by the increased capital and operating costs for retrofits. Capital and operating costs increase across all ownership types, but the direction of changes in electricity revenues varies among ownership types. All ownership types, with the exception of private entities, experience a net gain in electricity revenues under the MATS, unlike projections from the EPA's modeling during the proposal, where only municipals benefitted from higher electricity revenues. The change in electricity revenue takes into account both the profit lost from units that do not operate under the policy case and the difference in revenue for operating units under the policy case. According to the EPA's modeling, an estimated 274 MW of capacity owned by small entities are considered uneconomic to operate under the policy case, resulting in a net loss of $13 million (in 2007$) in profits. On the other hand, many operating units actually increase their electricity revenue due to higher electricity prices under MATS. In addition, as mentioned above, the EPA's modeling indicates one unit finds it economical to increase its capacity factor significantly under the policy case which results in significantly higher revenues offsetting the costs.

6. Description of Steps To Minimize Impacts on Small Entities

Consistent with the requirements of the RFA and SBREFA, the EPA has taken steps to minimize the significant economic impact on small entities. Because this rule does not affect units with a generating capacity of less than 25 MW, small entities that do not own at least one generating unit with a capacity greater than 25 MW are not subject to the rule. According to the EPA's analysis, among the coal- and oil-fired EGUs (*i.e.*, excluding combined cycle gas turbines and gas combustion turbines) about 26 potentially small entities only own EGUs with a capacity less than or equal to 25 MW, and none of those entities are subject to the final

rule based on the statutory definition of potentially regulated units.

For units affected by the proposed rule, the EPA considered a number of comments received, both during the Small Business Advocacy Review (SBAR) Panel and the public comment period. While none of the alternatives adopted is specifically applied to small entities, the EPA believes these modifications will make compliance less onerous for all regulated units, including those owned by small entities.

a. Work practice standards. The EPA proposed numerical emission standards that would apply at all times, including during periods of startup and shutdown. After reviewing comments and other data regarding the nature of these periods of operation, the EPA is finalizing a work practice standard for periods of startup and shutdown. The EPA is also finalizing work practice standards for organic HAP from all subcategories of EGUs. Descriptions of the work practice requirements for startup and shutdown, as well as organic HAP and limited-use liquid oil-fired EGUs, can be found in section VI.D–E. of the preamble.

b. Continuous compliance and notification, record-keeping, and reporting. The final rule greatly simplifies the continuous compliance requirements and provides two basic approaches for most situations: use of continuous monitoring and periodic testing. The frequency of periodic testing has been decreased from monthly in the proposal to quarterly in the final rule. In addition to simplifying compliance, the EPA believes these changes considerably reduce the overall burden associated with recordkeeping and reporting. These changes to the final rule are described in more detail in Section VI.G–H of this preamble.

c. Subcategorization. The Small Entity Representatives on the SBAR Panel were generally supportive of subcategorization and suggested a number of additional subcategories the EPA should consider when developing the final rule. Although it was not consistent with the statute to adopt the proposed subcategories, the EPA maintained the existing subcategories and split the "liquid oil-fired units" subcategory into three subcategories—continental, non-continental units, and limited-use units.

d. MACT floor calculations. As recommended by the EPA SBAR Panel representative, the EPA established the MACT floors using all the available ICR data that was received to the maximum extent possible consistent with the CAA requirements. The Agency believes this approach reasonably ensures that the emission limits selected as the MACT floors adequately represent the level of emissions actually achieved by the average of the units in the top 12 percent, considering operational variability of those units.

e. Alternatives not adopted. The EPA did not adopt several of the suggestions posed either during the SBAR Panel or public comment period. The EPA did not propose a percent reduction standard as an alternative to the concentration-based MACT floor. The percent reduction format for Hg and other HAP emissions would not have addressed the EPA's consideration of coal preparation practices that remove Hg and other HAP before firing. Also, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s), and such an approach would be difficult to implement and enforce. Furthermore, the EPA does not believe the percent reduction standard is in line with the Court's interpretation of the CAA section 112 requirements. Even if we believed it was appropriate to establish a percent reduction standard, we do not have the data necessary to establish percent reduction standards for HAP, as explained further in the response to comments document.

The EPA determined not to establish GACT standards for area sources for a number of reasons. The data show that similar HAP emissions and control technologies are found on both major and area sources greater than 25 MW, and some large units are synthetic area sources. In fact, because of the significant number of well-controlled EGUs of all sizes, we believe it would be difficult to make a distinction between MACT and GACT. Moreover, the EPA believes the standards for area source EGUs should reflect MACT, rather than GACT, because there is no essential difference between area source and major source EGUs with respect to emissions of HAP.

The EPA determined not to exercise its discretionary authority to establish health-based emission standards for HCl and other HAP acid gases. Given the limitations of the currently available information (*e.g.*, the HAP mix where EGUs are located, and the cumulative impacts of respiratory irritants from nearby sources), the environmental effects of HCl and the other acid gas HAP, and the significant co-benefits from reductions in criteria pollutants the EPA determined that setting a conventional MACT standard for HCl and the other acid gas HAP was the appropriate course of action.

As required by SBREFA section 212, the EPA also is preparing a Small Entity Compliance Guide to help small entities comply with this rule. Small entities will be able to obtain a copy of the Small Entity Compliance guide at the following Web site: *http://www.epa.gov/airquality/powerplanttoxics/actions.html.*

D. Unfunded Mandates Reform Act of 1995

Title II of the 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 UMRA section 202, we 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 a rule for which a written statement is needed, UMRA section 205 generally requires us 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 UMRA section 205 do not apply when they are inconsistent with applicable law. Moreover, UMRA section 205 allows us 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 we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under UMRA section 203. 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 regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this rule contains 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. Accordingly, we have prepared a written statement entitled "Unfunded Mandates Reform Act Analysis" under

UMRA section 202 that is within the RIA and which is summarized below.

1. Statutory Authority

As discussed elsewhere in this preamble, the statutory authority for this rulemaking is CAA section 112. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. CAA section 112(b) lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

CAA section 112(d) directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT-based standards. This NESHAP applies to all coal- and oil-fired EGUs.

In compliance with UMRA section 205(a), we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives were presented in the RIA for the rulemaking.

The regulatory alternative upon which this rule is based represents the MACT floor for all regulated pollutants for all but one EGU subcategory for all but one regulated pollutant for that subcategory. These MACT floor-based standards represent the least costly and least burdensome alternative. Beyond-the-floor emission limits for Hg are for existing coal-fired EGUs in the subcategory for low rank virgin coal EGUs.

2. Social Costs and Benefits

The RIA prepared for this rule including the Agency's assessment of costs and benefits is in the docket.

It is estimated that HAP would be reduced by thousands of tons in 2015, relative to the base case, including reductions in HCl, HF, metallic HAP (including Hg), and several other organic HAP from EGUs. Studies have determined a relationship between exposure to certain of these HAP and the onset of cancer; however, the Agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, significant reductions in $PM_{2.5}$ and SO_2 will occur, including approximately 53 thousand tons of $PM_{2.5}$ and over 1 million tons of SO_2. These reductions will occur by 2016 and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) is a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks, and work-lost days (*i.e.*, days when employees are unable to work). Although we are unable to monetize the benefits associated with the HAP emissions reductions other than for Hg or all benefits associated with Hg reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2016 associated with the implementation of the final rule range from $37 billion to $90 billion (2007 dollars) when using a 3 percent discount rate or from $33 billion to $81 billion (2007 dollars) when using a 7 percent discount rate). Our estimate of costs is $9.6 billion (2007 dollars). For more detailed information on the benefits and costs estimated for this rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

The UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by this rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of this rule are discussed previously in this preamble.

The EPA assessed the economic and financial impacts of the rule on government-owned entities using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent of base revenues. The EPA projects that 42 government entities will have compliance costs greater than 1 percent of base generation revenue in 2016, and 32 may experience compliance costs greater than 3 percent of base revenues. Overall, 6 units owned by government entities are expected to retire. The most significant components of incremental costs to these entities are the increased capital and operating costs, followed by changes in electricity revenues. For more details on these results and the methodology behind their estimation, see the results included in chapter 7 of the RIA.

4. Effects on the National Economy

The UMRA requires that we estimate the effect of this rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of this rule is presented in the RIA in the docket. This analysis provides estimates of the effect of this rule on some of the categories mentioned above.

The results of the economic impact analysis are summarized previously in this preamble. The results show that, relative to baseline, there will be an average 3.1 percent increase in electricity price on average nationwide in 2016, with the range of increases from 1.3 percent to 6.3 percent in regions throughout the U.S., and a less than 1 percent increase in natural gas price nationwide in 2016. The roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[377] Power generation from coal-fired plants will fall by about 2 percent nationwide in 2016. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the Agency's analysis, as a result of this rule. To put the electricity price effects in context, the roughly 3 percent incremental increase in aggregate end-user electricity prices projected to occur over the next 4 years is about the same as the 3 percent absolute average change in total end-user electricity prices observed on an annual basis.[378] Furthermore, the roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[379] Even with this rule in effect, electricity prices are projected to be lower in 2015 and 2020 than they were in 2010.[380]

5. Consultation With Government

The UMRA requires that we describe the extent of the Agency's prior consultation with affected state, local,

[377] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

[378] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 t0 2010, Table 8–10.

[379] Ibid.

[380] Ibid., EIA AEO 2010, Table–10 for price levels; and Chapterr 3 of the RIA for electricity price differential.

and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, UMRA section 203 requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a regulatory action. Consistent with the intergovernmental consultation provisions of UMRA section 204, the EPA initiated consultations with governmental entities affected by this rule. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting held on October 27, 2010, in Washington, DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations of elected state and local officials have been identified by the EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. The purposes of the consultation were to provide general background on the rule, answer questions, and solicit input from state/local governments. During the meeting, officials asked clarifying questions regarding CAA section 112 requirements and central decision points presented by the EPA (*e.g.*, use of surrogate pollutants to address HAP, subcategorization of source category, assessment of emissions variability). They also expressed uncertainty with regard to how utility boilers owned/operated by state and local entities would be impacted, as well as with regard to the potential burden associated with implementing the rule on state and local entities (*i.e.*, burden to re-permit affected EGUs or update existing permits). Officials requested, and the EPA provided, addresses associated with the 112 state and local governments estimated to be potentially impacted by the rule. The EPA has not received additional questions or requests from state or local officials.

Consistent with UMRA section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. Because the potential existed for a significant impact for substantial number of small entities, the EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of the rule. As part of that process, the EPA considered several options, which are discussed previously in this preamble. Those options included establishing emission limits, establishing work practice standards, establishing subcategories, and consideration of monitoring options. The regulatory alternative selected is a combination of the options considered and includes provisions regarding a number of the recommendations resulting from the SBAR Panel process as described below (see the Regulatory Flexibility Act discussion in this section of the preamble for more detail).

E. Executive Order 13132, Federalism

Under EO 13132, the EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or the EPA consults with state and local officials early in the process of developing the final action.

The EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. Accordingly, the EPA provides the following federalism summary impact statement as required by section 6(b) of EO 13132.

Based on estimates in the RIA, provided in the docket, the final rule may have federalism implications because the rule may impose approximately $294 million in annual direct compliance costs on an estimated 96 state or local governments. Specifically, we estimate that there are 80 municipalities, 5 states, and 11 political subdivisions (*i.e.*, a public district with territorial boundaries embracing an area wider than a single municipality and frequently covering more than one county for the purpose of generating, transmitting and distributing electric energy) that may be directly impacted by this final rule. Responses to the EPA's 2010 ICR were used to estimate the nationwide number of potentially impacted state or local governments. As previously explained, this 2010 survey was submitted to all coal- and oil-fired EGUs listed in the 2007 version of DOE/EIA's "Annual Electric Generator Report," and "Power Plant Operations Report."

The EPA consulted with state and local officials in the process of developing the rule to permit them to have meaningful and timely input into its development. The EPA met with 10 national organizations representing state and local elected officials to provide general background on the rule, answer questions, and solicit input. In the final rule, EPA has provided flexibilities that will lower compliance costs for these entities. The EPA also recognizes that municipalities may need a longer compliance timeframe because of required approval processes.

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

Subject to EO 13175 (65 FR 67249; November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. Executive Order 13175 requires the 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 EPA has concluded that this action may have tribal implications. The EPA offered consultation with tribal officials early in the regulation development process to permit them an opportunity to have meaningful and timely input. Consultation letters were sent to 584 tribal leaders and provided information regarding the EPA's development of this rule and offered consultation. At the request of the tribes, three consultation meetings were held: December 7, 2010, with the Upper Sioux Community of Minnesota; December 13, 2010, with Moapa Band of Paiutes, Forest County Potawatomi, Standing Rock Sioux Tribal Council, and Fond du Lac Band of Chippewa; January 5, 2011, with the Forest County Potawatomi, and a representative from the National Tribal Air Association (NTAA). In these meetings, the EPA presented the authority under the CAA used to develop these rules and an overview of the industry and the industrial processes that have the potential for regulation. Tribes expressed concerns about the impact of EGUs in Indian country. Specifically, they were concerned about potential Hg deposition and the impact on the water resources of the tribes, with particular concern about the impact on subsistence

lifestyles for fishing communities, the cultural impact of impaired water quality for ceremonial purposes, and the economic impact on tourism. In light of these concerns, the tribes expressed interest in an expedited implementation of the rule. Other concerns expressed by tribes related to how the Agency would consider variability in setting the standards, and the use of tribal-specific fish consumption data from the tribes in our assessments. They were not supportive of using work practice standards as part of the rule, and asked the Agency to consider going beyond the MACT floor to offer more protection for the tribal communities.

In addition to these consultations, the EPA also conducted outreach on this rule through presentations at the National Tribal Forum in Milwaukee, WI; phone calls with the NTAA; and a webinar for tribes on the proposed rule. The EPA specifically requested tribal data that could support the appropriate and necessary analyses and the RIA for this rule. In addition, the EPA held individual consultations with the Navajo Nation on October 12, 2011; as well as the Gila River Indian Community, Ak-Chin Indian Community, and the Hopi Nation on October 14, 2011. These tribes expressed concerns about the impact of the rule on the Navajo Generating Station (NGS), the impact on the cost of the water allotted to the tribes from the Central Arizona Project (CAP), the impact on tribal revenues from the coal mining operations (*i.e.*, assumptions about reduced mining if NGS were to retire one or more units), and the impacts on employment of tribal members at both the NGS and the mine. More specific comments can be found in the docket.

The EPA will continue to work with these and other potentially affected tribes as this final rule is implemented.

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

This final rule is subject to EO 13045 (62 FR 19885; April 23, 1997) because it is an economically significant regulatory action as defined by EO 12866, and EPA believes that the environmental health or safety risk addressed by this action may have a disproportionate effect on children. Accordingly, we have evaluated the environmental health or safety effects of the standards on children.

Although this final rule is based on technology performance, the standards are designed to protect against hazards to public health with an adequate margin of safety as described in Section III of this preamble. The protection offered by this rule is particularly important for children, especially the developing fetus. As referenced in Chapter 4 of the RIA, "Mercury and Other HAP Benefits Analysis," children are more vulnerable than adults to many HAP emitted by EGUs due to differential behavior patterns and physiology. These unique susceptibilities were carefully considered in a number of different ways in the analyses associated with this rulemaking, and are summarized in the RIA. We also estimate substantial health improvements for children in the form of 130,000 fewer asthma attacks, 3,100 fewer emergency room visits due to asthma, 6,300 fewer cases of acute bronchitis, and approximately 140,000 fewer cases of upper and lower respiratory illness.

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

Executive Order 13211 (66 FR 28355; May 22, 2001) requires EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, OMB, for actions identified as "significant energy actions." This action, which is a significant regulatory action under EO 12866, is likely to have a significant adverse effect on the supply, distribution, or use of energy. We have prepared a Statement of Energy Effects for this action as follows.

We estimate a 3.1 percent price increase for electricity nationwide in 2016 and a less than 2 percent percentage fall in coal-fired power production as a result of this rule. The EPA projects that electric power sector-delivered natural gas prices will increase by about 0.6 percent over the 2015 to 2030 timeframe. For more information on the estimated energy effects, please refer to the economic impact analysis for this final rule. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

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

This rulemaking involves technical standards. The EPA cites the following standards in the final rule: EPA Methods 1, 2, 2A, 2C, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 23, 26, 26A, 29, 30B of 40 CFR part 60 and Method 320 of 40 CFR part 63. Consistent with the NTTAA, the EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 2F, 2G, 5D, and 19. The search and review results have been documented and are placed in the docket for the proposed rule.

The three voluntary consensus standards described below were identified as acceptable alternatives to EPA test methods for the purposes of the final rule.

The voluntary consensus standard American National Standards Institute (ANSI)/American Society of Mechanical Engineers (ASME) PTC 19–10–1981, "Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus]" is cited in the final rule for its manual method for measuring the O_2, CO_2, and CO content of exhaust gas. This part of ANSI/ASME PTC 19–10–1981 is an acceptable alternative to Method 3B.

The voluntary consensus standard ASTM D6348–03 (Reapproved 2010), "Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy" is acceptable as an alternative to Method 320 and is cited in the final rule, but with several conditions: (1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; and (2) In ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). In order for the test data to be acceptable for a compound, %R must be 70% ≥ R ≤ 130%. If the %R value does not meet this criterion for a target compound, the test data are not acceptable for that compound and the test must be repeated for that analyte (*i.e.*, the sampling and/or analytical procedure should be adjusted before a retest). The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound by using the following

equation: *Reported Result = (Measured Concentration in the Stack × 100)/% R.*

The voluntary consensus standard 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)," is an acceptable alternative to use of EPA Method 29 for Hg only or Method 30B for the purpose of conducting relative accuracy tests of Hg continuous monitoring systems under this final rule. Because of the limitations of this method in terms of total sampling volume, it is not appropriate for use in performance testing under this rule. In addition to the voluntary consensus standards the EPA used in the final rule, the search for emissions measurement procedures identified 16 other voluntary consensus standards. The EPA determined that 14 of these 16 standards identified for measuring emissions of the HAP or other pollutants subject to emission standards in the final rule were impractical alternatives to EPA test methods for the purposes of this final rule. Therefore, the EPA did not adopt these standards for this purpose. The reasons for this determination for the 14 methods are discussed below, and the remaining 2 methods are discussed later in this section.

The voluntary consensus standard ASTM D3154–00, "Standard Method for Average Velocity in a Duct (Pitot Tube Method)," is impractical as an alternative to EPA Methods 1, 2, 3B, and 4 for the purposes of this rulemaking because the standard appears to lack in quality control and quality assurance requirements. Specifically, ASTM D3154–00 does not include the following: (1) proof that openings of standard pitot tube have not plugged during the test; (2) if differential pressure gauges other than inclined manometers (*e.g.,* magnehelic gauges) are used, their calibration must be checked after each test series; and (3) the frequency and validity range for calibration of the temperature sensors.

The voluntary consensus standard ASTM D3464–96 (Reapproved 2001), "Standard Test Method Average Velocity in a Duct Using a Thermal Anemometer," is impractical as an alternative to EPA Method 2 for the purposes of this rule primarily because applicability specifications are not clearly defined, *e.g.,* range of gas composition, temperature limits. Also, the lack of supporting quality assurance data for the calibration procedures and specifications, and certain variability issues that are not adequately addressed by the standard limit the EPA's ability to make a definitive comparison of the method in these areas.

The voluntary consensus standard ISO 10780:1994, "Stationary Source Emissions—Measurement of Velocity and Volume Flowrate of Gas Streams in Ducts," is impractical as an alternative to EPA Method 2 in this rule. The standard recommends the use of an L-shaped pitot, which historically has not been recommended by the EPA. The EPA specifies the S-type design which has large openings that are less likely to plug up with dust.

The voluntary consensus standard, CAN/CSA Z223.2–M86 (1999), "Method for the Continuous Measurement of Oxygen, Carbon Dioxide, Carbon Monoxide, Sulphur Dioxide, and Oxides of Nitrogen in Enclosed Combustion Flue Gas Streams," is unacceptable as a substitute for EPA Method 3A because it does not include quantitative specifications for measurement system performance, most notably the calibration procedures and instrument performance characteristics. The instrument performance characteristics that are provided are non-mandatory and also do not provide the same level of quality assurance as the EPA methods. For example, the zero and span/calibration drift is only checked weekly, whereas the EPA methods require drift checks after each run.

Two very similar voluntary consensus standards, ASTM D5835–95 (Reapproved 2001), "Standard Practice for Sampling Stationary Source Emissions for Automated Determination of Gas Concentration," and ISO 10396:1993, "Stationary Source Emissions: Sampling for the Automated Determination of Gas Concentrations," are impractical alternatives to EPA Method 3A for the purposes of this final rule because they lack in detail and quality assurance/quality control requirements. Specifically, these two standards do not include the following: (1) Sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only).

The voluntary consensus standard ISO 12039:2001, "Stationary Source Emissions—Determination of Carbon Monoxide, Carbon Dioxide, and Oxygen—Automated Methods," is not acceptable as an alternative to EPA Method 3A. This ISO standard is similar to EPA Method 3A, but is missing some key features. In terms of sampling, the hardware required by ISO 12039:2001 does not include a 3-way calibration valve assembly or equivalent to block the sample gas flow while calibration gases are introduced. In its calibration procedures, ISO 12039:2001 only specifies a two-point calibration while EPA Method 3A specifies a three-point calibration. Also, ISO 12039:2001 does not specify performance criteria for calibration error, calibration drift, or sampling system bias tests as in the EPA method, although checks of these quality control features are required by the ISO standard.

The voluntary consensus standard ASTM D6522–00, "Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers" is not an acceptable alternative to EPA Method 3A for measuring CO and O_2 concentrations for this final rule as the method is designed for application to sources firing natural gas.

The voluntary consensus standard ASME PTC–38–80 R85 (1985), "Determination of the Concentration of Particulate Matter in Gas Streams," is not acceptable as an alternative for EPA Method 5 because ASTM PTC–38–80 is not specific about equipment requirements, and instead presents the options available and the pros and cons of each option. The key specific differences between ASME PTC–38–80 and the EPA methods are that the ASME standard: (1) Allows in-stack filter placement as compared to the out-of-stack filter placement in EPA Methods 5 and 17; (2) allows many different types of nozzles, pitots, and filtering equipment; (3) does not specify a filter weighing protocol or a minimum allowable filter weight fluctuation as in the EPA methods; and (4) allows filter paper to be only 99 percent efficient, as compared to the 99.95 percent efficiency required by the EPA methods.

The voluntary consensus standard ASTM D3685/D3685M–98, "Test Methods for Sampling and Determination of Particulate Matter in Stack Gases," is similar to EPA Methods 5 and 17, but is lacking in the following areas that are needed to produce quality, representative particulate data: (1) Requirement that the filter holder temperature should be between 120°C and 134°C, and not just "above the acid dew-point"; (2) detailed specifications

for measuring and monitoring the filter holder temperature during sampling; (3) procedures similar to EPA Methods 1, 2, 3, and 4, that are required by EPA Method 5; (4) technical guidance for performing the Method 5 sampling procedures, *e.g.*, maintaining and monitoring sampling train operating temperatures, specific leak check guidelines and procedures, and use of reagent blanks for determining and subtracting background contamination; and (5) detailed equipment and/or operational requirements, *e.g.*, component exchange leak checks, use of glass cyclones for heavy particulate loading and/or water droplets, operating under a negative stack pressure, exchanging particulate loaded filters, sampling preparation and implementation guidance, sample recovery guidance, data reduction guidance, and particulate sample calculations input.

The voluntary consensus standard ISO 9096:1992, "Determination of Concentration and Mass Flow Rate of Particulate Matter in Gas Carrying Ducts—Manual Gravimetric Method," is not acceptable as an alternative for EPA Method 5. Although sections of ISO 9096 incorporate EPA Methods 1, 2, and 5 to some degree, this ISO standard is not equivalent to EPA Method 5 for collection of PM. The standard ISO 9096 does not provide applicable technical guidance for performing many of the integral procedures specified in Methods 1, 2, and 5. Major performance and operational details are lacking or nonexistent, and detailed quality assurance/quality control guidance for the sampling operations required to produce quality, representative particulate data (*e.g.*, guidance for maintaining and monitoring train operating temperatures, specific leak check guidelines and procedures, and sample preparation and recovery procedures) are not provided by the standard, as in EPA Method 5. Also, details of equipment and/or operational requirements, such as those specified in EPA Method 5, are not included in the ISO standard, *e.g.*, stack gas moisture measurements, data reduction guidance, and particulate sample calculations.

The voluntary consensus standard CAN/CSA Z223.1–M1977, "Method for the Determination of Particulate Mass Flows in Enclosed Gas Streams," is not acceptable as an alternative for EPA Method 5. Detailed technical procedures and quality control measures that are required in EPA Methods 1, 2, 3, and 4 are not included in CAN/CSA Z223.1. Second, CAN/CSA Z223.1 does not include the EPA Method 5 filter weighing requirement to repeat weighing every 6 hours until a constant weight is achieved. Third, EPA Method 5 requires the filter weight to be reported to the nearest 0.1 milligram (mg), while CAN/CSA Z223.1 requires reporting only to the nearest 0.5 mg. Also, CAN/CSA Z223.1 allows the use of a standard pitot for velocity measurement when plugging of the tube opening is not expected to be a problem. The EPA Method 5 requires an S-shaped pitot.

The voluntary consensus standard EN 1911–1,2,3 (1998), "Stationary Source Emissions-Manual Method of Determination of HCl-Part 1: Sampling of Gases Ratified European Text-Part 2: Gaseous Compounds Absorption Ratified European Text-Part 3: Adsorption Solutions Analysis and Calculation Ratified European Text," is impractical as an alternative to EPA Methods 26 and 26A. Part 3 of this standard cannot be considered equivalent to EPA Method 26 or 26A because the sample absorbing solution (water) would be expected to capture both HCl and chlorine gas, if present, without the ability to distinguish between the two. The EPA Methods 26 and 26A use an acidified absorbing solution to first separate HCl and chlorine gas so that they can be selectively absorbed, analyzed, and reported separately. In addition, in EN 1911 the absorption efficiency for chlorine gas would be expected to vary as the pH of the water changed during sampling.

The voluntary consensus standard EN 13211 (1998), is not acceptable as an alternative to the Hg portion of EPA Method 29 primarily because it is not validated for use with impingers, as in the EPA method, although the method describes procedures for the use of impingers. This European standard is validated for the use of fritted bubblers only and requires the use of a side (split) stream arrangement for isokinetic sampling because of the low sampling rate of the bubblers (up to 3 liters per minute, maximum). Also, only two bubblers (or impingers) are required by EN 13211, whereas EPA Method 29 require the use of six impingers. In addition, EN 13211 does not include many of the quality control procedures of EPA Method 29, especially for the use and calibration of temperature sensors and controllers, sampling train assembly and disassembly, and filter weighing.

Two of the 16 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rule because they are under development by a voluntary consensus body: ASME/BSR MFC 13M, "Flow Measurement by Velocity Traverse," for EPA Method 2 (and possibly 1); and ASME/BSR MFC 12M, "Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters," for EPA Method 2.

Finally, in addition to the three voluntary consensus standards identified as acceptable alternatives to EPA methods required in the final rule, the EPA is also specifying four voluntary consensus standards in the rule for use in sampling and analysis of liquid oil samples for moisture content. These standards are: ASTM D95–05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," ASTM D4006–11, "Standard Test Method for Water in Crude Oil by Distillation," ASTM D4177–95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," and ASTM D4057–06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products."

Table 5, section 4.1.1.5 of appendix A, and section 3.1.2 of appendix B to subpart UUUUU, 40 CFR part 63, list the EPA testing methods included in the final rule. Under section 63.7(f) and section 63.8(f) of subpart A of the General Provisions, a source may apply to the EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures specified.

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 (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ 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 U.S.

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, and indigenous populations because it increases the level of environmental protection for all affected populations without having any disproportionately

high and adverse human health or environmental effects on any population, including any minority, low income, and indigenous populations.

This final rule establishes national emission standards for new and existing EGUs that combust coal and oil. The EPA estimates that there are approximately 1,400 units located at 600 facilities covered by this final rule.

This final rule will reduce emissions of all the listed HAP that come from EGUs. This includes metals (Hg, As, Be, Cd, Cr, Pb, Mn, Ni, and Se), organics (POM, acetaldehyde, acrolein, benzene, dioxins, ethylene dichloride, formaldehyde, and PCB), and acid gases (HCl and HF). At sufficient levels of exposure, these pollutants can cause a range of health effects including cancer; irritation of the lungs, skin, and mucous membranes; effects on the central nervous system such as memory and IQ loss and learning disabilities; damage to the kidneys; and other acute health disorders.

The final rule will also result in substantial reductions of criteria pollutants such as CO, PM, and SO_2. Sulfur dioxide is a precursor pollutant that is often transformed into fine PM ($PM_{2.5}$) in the atmosphere. Reducing direct emissions of $PM_{2.5}$ and SO_2 will, as a result, reduce concentrations of $PM_{2.5}$ in the atmosphere. These reductions in $PM_{2.5}$ will provide large health benefits, such as reducing the risk of premature mortality for adults, chronic and acute bronchitis, childhood asthma attacks, and hospitalizations for other respiratory and cardiovascular diseases. (For more details on the health effects of metals, organics, and $PM_{2.5}$, please refer to the RIA contained in the docket for this rulemaking.) This final rule will also have a small effect on electricity and natural gas prices but has the potential to affect the cost structure of the utility industry and could lead to shifts in how and where electricity is generated.

This final rule is one of a group of regulatory actions that the EPA has taken and will take over the next several years to respond to statutory and judicial mandates that will reduce exposure to HAP and $PM_{2.5}$, as well as to other pollutants, from EGUs and other sources. In addition, the EPA will pursue energy efficiency improvements throughout the economy, along with other federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements. Together, these rules and actions will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in many, if not most, of these actions from EJ communities, among many others.

1. Key EJ Aspects of the Rule

This is an air toxics rule; therefore, it does not permit emissions trading among sources. Instead, this final rule will place a limit on the rates of Hg and other HAP emitted from each affected EGU. As a result, emissions of Hg and other HAP such as HCl will be substantially reduced in the vast majority of states. In some states, however, there may be small increases in Hg and other HAP emissions due to shifts in electricity generation from EGUs with higher emission rates to EGUs with already low emission rates. Hydrogen chloride emissions are projected to increase at a small number of sources but that does not lead to any increased emissions at the state level.

The primary risk analysis to support the finding that this final rule is both appropriate and necessary includes an analysis of the effects of Hg from EGUs on people who rely on freshwater fish they catch as a regular and frequent part of their diet. These groups are characterized as subsistence level fishing populations or fishers. A significant portion of the data in this analysis came from published studies of EJ communities where people frequently consume locally-caught freshwater fish. These communities included: (1) White and black populations (including female and poor strata) surveyed in South Carolina; (2) Hispanic, Vietnamese and Laotian populations surveyed in California; and (3) Great Lakes tribal populations (Chippewa and Ojibwe) active on ceded territories around the Great Lakes. These data were used to help estimate risks to similar populations beyond the areas where the study data were collected. For example, while the Vietnamese and Laotian survey data were collected in California, given the ethnic (heritage) nature of these high fish consumption rates, we assumed that they could also be associated with members of these ethnic groups living elsewhere in the U.S. Therefore, the high-end consumption rates referenced in the California study for these ethnic groups were used to model risk at watersheds elsewhere in the U.S. As a result of this approach, the specific fish consumption patterns of several different EJ groups are fundamental to the EPA's assessment of both the underlying risks that make this final rule appropriate and necessary, and of the analysis of the benefits of reducing exposure to Hg and the other HAP.

The EPA's full analysis of risks from consumption of Hg-contaminated fish is contained in the RIA for this rule. The effects of this final rule on the health risks from Hg and other HAP are presented in the preamble and in the RIA for this rule.

2. Potential Environmental and Public Health Impacts to Minority, Low Income, or Tribal Populations

The EPA has conducted several analyses that provide additional insight on the potential effects of this rule on EJ communities. These include: (1) The socio-economic distribution of people living close to affected EGUs who may be exposed to pollution from these sources; and (2) an analysis of the distribution of health effects expected from the reductions in $PM_{2.5}$ that will result from implementation of this final rule (co-benefits).

a. Socio-Economic Distribution. As part of the analysis for this final rule, the EPA reviewed the aggregate demographic makeup of the communities near EGUs covered by this final rule. Although this analysis gives some indication of populations that may be exposed to levels of pollution that cause concern, it does not identify the demographic characteristics of the most highly affected individuals or communities. Electric generating units usually have very tall emission stacks; this tends to disperse the pollutants emitted from these stacks fairly far from the source. In addition, several of the pollutants emitted by these sources, such as a common form of Hg and SO_2, are known to travel long distances and contribute to adverse impacts on both the environment and human health hundreds or even thousands of miles from where they were emitted (in the case of elemental Hg, globally).

The proximity-to-the-source review is included in the analysis for this final rule because some EGUs emit enough HAP such as Ni or Cr(VI) to cause elevated lifetime cancer risks greater than 1 in a million in nearby communities. In addition, the EPA's analysis indicates that there are localized areas with potential for elevated levels of Hg deposition around most U.S. EGUs.[381]

The analysis of demographic data used proximity-to-the-source as a surrogate for exposure to identify those populations considered to be living near affected sources, such that they have notable exposures to current HAP

[381] See Excess Local Deposition TSD for more detail.

emissions from these sources. The demographic data for this analysis were extracted from the 2000 census data which were provided to the EPA by the U.S. Census Bureau. Distributions by race are based on demographic information at the census block level, and all other demographic groups are based on the extrapolation of census block group level data to the census block level. The socio-demographic parameters used in the analysis included the following categories: Racial (White, African American, Native American, Other or Multiracial, and All Other Races); Ethnicity (Hispanic); and Other (Number of people below the poverty line, Number of people with ages between 0 and 18, Number of people greater than or equal to 65, Number of people with no high school diploma).

In determining the aggregate demographic makeup of the communities near affected sources, the EPA focused on those census blocks within three miles of affected sources and determined the demographic composition (*e.g.*, race, income, etc.) of these census blocks and compared them to the corresponding compositions nationally. The radius of 3 miles (or approximately 5 kilometers) is consistent with other demographic analyses focused on areas around potential sources. In addition, air quality modeling experience has shown that the area within three miles of an individual source of emissions can generally be considered the area with the highest ambient air levels of the primary pollutants being emitted for most sources, both in absolute terms and relative to the contribution of other sources (assuming there are other sources in the area, as is typical in urban areas). Although facility processes and fugitive emissions may have more localized impacts, the EPA acknowledges that because of various stack heights there is the potential for dispersion beyond 3 miles. To the extent that any minority, low income, and indigenous subpopulation is disproportionately impacted by the current emissions as a result of the proximity of their homes to these sources, that subpopulation also stands to see increased environmental and health benefit from the emissions reductions called for by this rule. The results of the EPA's demographic analysis for affected sources are shown in the following table: [382] [383]

TABLE 12—COMPARATIVE SUMMARY OF THE DEMOGRAPHICS WITHIN 5 KM (3 MILES) OF THE AFFECTED SOURCES

[Population in millions] [382]

	White	African American	Native American	Other and multi-racial	Hispanic	Minority [383]	Below poverty line
Near Source Total (3 mi)	8.78	2.51	0.10	2.52	2.86	5.13	2.43
% of Near Source Total	63	18	1	18	21	37	17
National Total	215	35	2.49	33.3	39.1	70.8	37.1
% of National Total	75	12	1	12	14	25	13

[382] Racial and ethnic categories overlap and cannot be summed.
[383] The "Minority" population is the overall population (in the first row) minus white population (in the second row).

The data indicate that coal-fired EGUs are located in areas where the minority share of the population living within a three mile buffer is higher than the national average by 12 percentage points or 48 percent. For these same areas, the percent of the population below the poverty line is also higher than the national average by 4 percentage points or 31 percent. These results are presented in more detail in the "Review of Proximity Analysis," February 2011, a copy of which is available in the docket.

b. $PM_{2.5}$ (Co-Benefits) Analysis. As mentioned above, many of the steps EGUs will take to reduce their emissions of air toxics as required by this final rule will also reduce emissions of PM and SO_2. As a result, this final rule will reduce concentrations of $PM_{2.5}$ in the atmosphere. Exposure to $PM_{2.5}$ can cause or contribute to adverse health effects, such as asthma and heart disease, that significantly affect many minority, low-income, and tribal individuals and their communities. Fine PM ($PM_{2.5}$) is particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure can cause premature death and trigger heart attacks, asthma attacks in children and adults with asthma, chronic and acute bronchitis, and emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. Missing work due to illness or the illness of a child is a particular problem for people who have jobs that do not provide paid sick days. Low-wage employees also risk losing their jobs if they are absent too often, even if it is due to their own illness or the illness of a child or other relative. Finally, many individuals in these communities lack access to high quality health care to treat these types of illnesses. Due to all these factors, many minority and low-income communities are particularly susceptible to the health effects of $PM_{2.5}$ and receive a variety of benefits from reducing it.

We estimate that in 2016 the annual PM-related benefits of the final rule for adults include approximately 4,200 to 11,000 fewer premature mortalities, 2,900 fewer cases of chronic bronchitis, 4,800 fewer non-fatal heart attacks, 2,600 fewer hospitalizations (for respiratory and cardiovascular disease combined), 3.2 million fewer days of restricted activity due to respiratory illness and approximately 540,000 fewer lost work days. As described in EO 13045, Protection of Children from Environmental Health Risks and Safety Risks, we also estimate substantial health improvements for children.

We also examined the $PM_{2.5}$ mortality risks according to race, income, and educational attainment. We then estimated the change in $PM_{2.5}$ mortality risk as a result of this final rule among people living in the counties with the highest (top 5 percent) $PM_{2.5}$ mortality risk in 2005. We then compared the change in risk among the people living in these "high-risk" counties with people living in all other counties.

In 2005, people living in the highest risk counties and in the poorest counties had a substantially higher risk of $PM_{2.5}$-related death than people living in the other 95 percent of counties. This was

true regardless of race; the difference between the groups of counties for each race was large while the differences among races in both groups of counties was very small. In contrast, the analysis found that people with less than high school education had a significantly greater risk from $PM_{2.5}$ mortality than people with a greater than high school education. This was true both for the highest-risk counties and for the other counties. In summary, the analysis indicates that in 2005, educational status, living in one of the poorest counties, and living in a high-risk county are associated with higher $PM_{2.5}$ mortality risk while race is not.

Our analysis demonstrates that this final rule will significantly reduce the $PM_{2.5}$ mortality among all populations of different races living throughout the U.S. compared to both 2005 and 2016 pre-rule (*i.e.*, base case) levels. The analysis indicates that people living in counties with the highest rates (top 5 percent) of $PM_{2.5}$ mortality risk in 2005 receive the largest reduction in mortality risk after this rule takes effect. We also find that people living in the poorest 5 percent of the counties receive a larger reduction in $PM_{2.5}$ mortality risk than all other counties. More information can be found in Section 7.11 of the RIA.

The EPA estimates that the benefits of the final rule are distributed among races, income levels, and levels of education fairly evenly. However, the analysis does indicate that this final rule in conjunction with the implementation of existing or final rules (*e.g.*, the CSAPR) will reduce the disparity in risk between those in the highest-risk counties and the other 95 percent of counties for all races and educational levels. In addition, in many cases implementation of this final rule and other rules will, together, reduce risks in the highest-risk counties to the approximate level of risk for the rest of the counties as it existed before implementation of the rule.

These results are presented in more detail in Section 7.11 of the RIA.

3. Meaningful Public Participation

The EPA defines "environmental justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. To promote meaningful involvement, the EPA publicized the rulemaking via newsletters, EJ listserves, and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (*http://yosemite.epa.gov/opei/RuleGate.nsf/*). During the comment period, the EPA discussed the proposed rule via a conference call with communities, conducted a community-oriented webinar on the proposed rule, and posted the webinar presentation on-line. The EPA also held three public hearings to receive additional input on the proposal.

There will continue to be opportunities for public notice and comment as the utilities move forward with implementation of this rule. Once the rule is finalized, affected EGUs will need to update their Title V operating permits to reflect their new emission limits, any other new applicable requirements, and the associated monitoring and recordkeeping from this rule. The Title V permitting process provides that when most permits are reopened (for example, to incorporate new applicable requirements) or renewed, there must be opportunity for public review and comments. In addition, after the public review process, the EPA has an opportunity to review the proposed permit and object to its issuance if it does not meet CAA requirements.

4. Additional Analysis

In addition to the previously described assessment of EJ impacts, the EPA conducted an analysis of sub-populations with particularly high potential risks of Hg exposure due to high rates of fish consumption. These populations overlap in many cases with traditional EJ populations and would benefit from Hg reductions resulting from this rule. The EPA also conducted an analysis of the distribution of $PM_{2.5}$-related mortality risk according to the race, income and education of the population and how MATS changes this distribution. These analyses can be found in Section 7.12 of the RIA.

5. Summary

This final rule strictly limits the emissions rate of Hg and other HAP from every affected EGU. The EPA's analysis indicates substantial health benefits, including for minority, low income, and indigenous populations, from reductions in $PM_{2.5}$.

The EPA's analysis also indicates reductions in risks for individuals, including for members of minority populations, who eat fish frequently from U.S. lakes and rivers and who live near affected sources. Based on all the available information, the EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, and indigenous populations. The EPA is providing multiple opportunities for EJ communities to both learn about and comment on this rule and welcomes their participation as implementation of the rule proceeds.

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 U.S. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective April 16, 2012.

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, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: December 16, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, 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 60.17 is amended:

■ a. By redesignating paragraph (a)(93), added March 21, 2011, at 76 FR 15750, and delayed indefinitely at 76 FR 28664, May 18, 2011, as paragraph (a)(96);

■ b. By redesignating paragraphs (a)(91) and (a)(92) as paragraphs (a)(94) and (a)(95);
■ c. By redesignating paragraphs (a)(89) and (a)(90) as paragraphs (a)(91) and (a)(92);
■ d. By redesignating paragraphs (a)(54) through (a)(88) as paragraphs (a)(55) through (a)(89);
■ e. By adding paragraph (a)(54);
■ f. By adding paragraph (a)(90); and
■ g. By adding paragraph (a)(93) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(54) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, approved September 1, 2008, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(90) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, approved July 15, 2011, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(93) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, approved August 1, 2010, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

Subpart B—[Amended]

■ 3. Section 60.21 is amended as follows:
■ a. By revising paragraph (a).
■ b. By revising paragraph (f).
■ c. By removing paragraph (k).

§ 60.21 Definitions.

* * * * *

(a) *Designated pollutant* means any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

* * * * *

(f) *Emission standard* means a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions.

* * * * *

■ 4. Section 60.24 is amended as follows:
■ a. By revising paragraph (b)(1).
■ b. By removing paragraph (h).

§ 60.24 Emission standards and compliance schedules.

* * * * *

(b) * * *

(1) Emission standards shall either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable. Such cases will be identified in the guideline documents issued under § 60.22. Where emission standards prescribing equipment specifications are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such specifications, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

* * * * *

Subpart D—[Amended]

■ 5. The subpart heading for Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators

■ 6. Section 60.40 is amended by revising paragraph (e) to read as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(e) Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.

■ 7. Section 60.41 is amended by adding the definition of "natural gas" in alphabetical order to read as follows:

§ 60.41 Definitions.

* * * * *

Natural gas means a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

* * * * *

■ 8. Section 60.42 is amended as follows:
■ a. By revising paragraph (a) introductory text.
■ b. By adding paragraph (d).
■ c. By adding paragraph (e).

§ 60.42 Standard for particulate matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (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:

* * * * *

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM is exempt from the PM standards specified in paragraph (a) of this section.

■ 9. Section 60.45 is amended as follows:
■ a. By revising paragraph (a).
■ b. By revising paragraph (b) introductory text.
■ c. By revising paragraphs (b)(1) through (5).
■ d. By revising paragraph (b)(6) introductory text.
■ e. By revising paragraphs (b)(7)(i)(A) through (C).
■ f. By revising paragraph (b)(7)(ii)(B).
■ g. By adding paragraph (b)(8).

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring 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 and COMS 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 combusts only gaseous or liquid fossil fuel (excluding residual oil)

with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO_2 emissions are not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis or fuel receipts.

(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 is not required to and elects not to install any CEMS for either SO_2 or NO_X, a CEMS for measuring either O_2 or CO_2 is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for 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 0.30 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.

* * * * *

(7) * * *

(i) * * *

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(ii) * * *

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

* * * * *

Subpart Da—[Amended]

■ 10. The subpart heading for Subpart Da is revised to read as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

■ 11. Section 60.40Da is amended by revising paragraphs (b)(1) and (e) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

* * * * *

(b) * * *

(1) The IGCC electric utility steam generating unit is capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel) in the combustion turbine engine and associated heat recovery steam generator; and

* * * * *

(e) Applicability of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) through (3) of this section.

(1) Affected facilities (*i.e.* heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (*i.e.* heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators use with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (*i.e.* duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKKK, as applicable, of this part.)

(3) Any affected facility that meets the applicability requirements and is subject to subpart Eb or subpart CCCC of this part is not subject to the emission standards under subpart Da.

■ 12. Section 60.41Da is amended as follows:

■ a. By revising the definitions of "boiler operating day", "gaseous fuel", "integrated gasification combined cycle electric utility steam generating unit", "natural gas", "petroleum", "potential combustion concentration", and "steam generating unit".

■ b. By adding the definitions of "affirmative defense", "combined heat and power", "gross energy output", "net energy output", "out-of-control period", and "petroleum coke" in alphabetical order.

■ c. By removing the definitions of "available purchase power", "cogeneration", "dry flue gas desulfurization technology ", "electric utility company", "emergency condition", "emission rate period", "gross output", "interconnected", "net system capacity", "principal company", "responsible official", "spare flue gas desulfurization system module", "spinning reserve", "system emergency reserves", and "system load".

§ 60.41Da Definitions.

* * * * *

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

* * * * *

Boiler operating day for units constructed, reconstructed, or modified before February 29, 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.

* * * * *

Combined heat and power, also known as "cogeneration," means a steam-generating unit that simultaneously produces both electric (and mechanical) and useful thermal energy from the same primary energy source.

* * * * *

Gaseous fuel means any fuel that is present as a gas at standard conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

* * * * *

Gross energy output means:

(1) For facilities constructed, reconstructed, or modified before May 4, 2011, the gross electrical or mechanical output from the affected facility plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process);

(2) For facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process);

(3) For combined heat and power facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility divided by 0.95 minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process);

(4) For a IGCC electric utility generating unit that coproduces chemicals constructed, reconstructed, or modified after May 3, 2011, the gross useful work performed is the gross electrical or mechanical output from the unit minus electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) that are associated with power production plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process). Auxiliary loads that are associated with power production are determined based on the energy in the coproduced chemicals compared to the energy of the syngas combusted in combustion turbine engine and associated duct burners.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction or repair. No solid fuel is directly burned in the unit during operation.

* * * * *

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net energy output means the gross energy output minus the parasitic load associated with power production. Parasitic load includes, but is not limited to, the power required to operate the equipment used for fuel delivery systems, air pollution control systems, wastewater treatment systems, ash handling and disposal systems, and other controls (*i.e.,* pumps, fans, compressors, motors, instrumentation, and other ancillary equipment required to operate the affected facility).

* * * * *

Out-of-control period means any period beginning with the quadrant corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the quadrant corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Petroleum for facilities constructed, reconstructed, or modified before May 4, 2011, means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil. For units constructed, reconstructed, or modified after May 3, 2011, *petroleum* means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Petroleum coke, also known as "petcoke," means a carbonization product of high-boiling hydrocarbon fractions obtained in petroleum processing (heavy residues). *Petroleum*

coke is typically derived from oil refinery coker units or other cracking processes.

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. For sulfur dioxide (SO_2) the potential combustion concentration is determined under § 60.50Da(c).

* * * * *

Steam generating unit for facilities constructed, reconstructed, or modified before May 4, 2011, 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). For units constructed, reconstructed, or modified after May 3, 2011, *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) plus any integrated combustion turbines and fuel cells.

* * * * *

■ 13. Section 60.42Da is revised to read as follows:

§ 60.42Da Standards for particulate matter (PM).

(a) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

(b) Except as provided in paragraphs (b)(1) and (b)(2) of this section, on and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere 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.

(1) An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart is exempt from the opacity standard specified in this paragraph (b) of this section.

(2) An owner or operator of an affected facility that combusts only natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

(c) Except as provided in paragraphs (d) and (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, but before May 4, 2011, 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, but before May 4, 2011, 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 any gases that contain PM in excess of:

(1) 13 ng/J (0.030 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) For an affected facility that commenced construction or reconstruction, 0.1 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.9 percent reduction) when combusting solid, liquid, or gaseous fuel, or

(3) For an affected facility that commenced modification, 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.8 percent reduction) when combusting solid, liquid, or gaseous fuel.

(e) Except as provided in paragraph (f) of this section, the owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall meet the requirements specified in paragraphs (e)(1) and (2) of this section.

(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 shall cause to be discharged into the atmosphere from that affected facility at all times except during periods of startup and shutdown, any gases that contain PM in excess of the applicable emissions limit specified in paragraphs (e)(1)(i) or (ii) of this section.

(i) For an affected facility which commenced construction or reconstruction, any gases that contain PM in excess of either:

(A) 11 ng/J (0.090 lb/MWh) gross energy output; or

(B) 12 ng/J (0.097 lb/MWh) net energy output.

(ii) For an affected facility which commenced modification, any gases that contain PM in excess of 13 ng/J (0.015 lb/MMBtu) heat input.

(2) During periods of startup and shutdown, the owner or operator shall meet the work practice standards specified in Table 3 to subpart UUUUU of part 63.

(f) An owner or operator of an affected facility that meets the conditions in either paragraphs (f)(1) or (2) of this section is exempt from the PM emissions limits in this section.

(1) The affected facility combusts only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and that does not use a post-combustion technology to reduce emissions of SO_2 or PM.

(2) The affected facility is operated under a PM commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da.

■ 14. Section 60.43Da is amended as follows:

■ a. The section heading is revised.

■ b. By revising paragraphs (a)(1) and (2).

■ c. By adding paragraphs (a)(3) and (4).

■ d. By removing and reserving paragraph (c).

■ e. By revising paragraph (f).

■ f. By revising paragraph (i).

■ g. By revising paragraph (k).

■ h. By adding paragraph (l).

■ i. By adding paragraph (m).

§ 60.43Da Standards for sulfur dioxide (SO_2).

(a) * * *

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction);

(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;

(3) 180 ng/J (1.4 lb/MWh) gross energy output; or

(4) 65 ng/J (0.15 lb/MMBtu) heat input.

* * * * *

(f) The SO_2 standards under this section do not apply to an owner or operator of an affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

* * * * *

(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 for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction).

(2) For an affected facility which commenced reconstruction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction).

(3) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction).

* * * * *

(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 for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emissions limit 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.

(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 230 ng/J (0.54 lb/MMBtu) heat input.

(l) Except as provided in paragraphs (j) and (m) 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 for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (l)(1) and (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO_2 in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 140 ng/J (1.2 lb/MWh) net energy output; or

(iii) 3 percent of the potential combustion concentration (97 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(m) 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 for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (m)(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.

(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 230 ng/J (0.54 lb/MMBtu) heat input.

■ 15. Section 60.44Da is revised to read as follows:

§ 60.44Da Standards for nitrogen oxides (NO_X).

(a) Except as provided in paragraph (h) 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 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 July 10, 1997 any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit in paragraphs (a)(1) and (2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emissions limit listed in the following table as applicable to the fuel type combusted and as determined on a 30-boiler operating day rolling average basis.

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:		

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
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) When two or more fuels are combusted simultaneously in an affected facility, the applicable emissions limit (E_n) is determined by proration using the following formula:

$$En = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

En = Applicable NO_X emissions limit 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.

(b) [Reserved]

(c) [Reserved]

(d) Except as provided in paragraph (h) 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 July 9, 1997, but before March 1, 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 emissions limit specified in paragraphs (d)(1) and (2) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_X in excess of 200 ng/J (1.6 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X in excess of 65 ng/J (0.15 lb/MMBtu) heat input.

(e) Except as provided in paragraphs (f) and (h) 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 but before May 4, 2011, 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 emissions limit specified in paragraphs (e)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_X in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input.

(3) For an affected facility which commenced modification, any gases that contain NO_X in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input.

(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 but before May 4, 2011, 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.

(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.

(3) In cases when during a 30-boiler operating 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 compliance 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.

(g) Except as provided in paragraphs (h) of this section and § 60.45Da, 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 May 3, 2011, 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 emissions limit specified in paragraphs (g)(1) through (3) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_X in excess of either:

(i) 88 ng/J (0.70 lb/MWh) gross energy output; or

(ii) 95 ng/J (0.76 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO_X in excess of either:

(i) 110 ng/J (0.85 lb/MWh) gross energy output; or

(ii) 120 ng/J (0.92 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_X in excess of 140 ng/J (1.1 lb/MWh) gross energy output.

(h) The NO_X emissions limits under this section do not apply to an owner or operator of an affected facility which is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

■ 16. Section 60.45Da is revised to read as follows:

§ 60.45Da Alternative standards for combined nitrogen oxides (NO_X) and carbon monoxide (CO).

(a) The owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011 as alternate to meeting the applicable NO_X emissions limits specified in § 60.44Da may elect to meet the applicable standards for combined NO_X and CO specified in paragraph (b) of this section.

(b) 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 commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) plus CO in excess of the applicable emissions limit specified in paragraphs (b)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_X plus CO in excess of either:

(i) 140 ng/J (1.1 lb/MWh) gross energy output; or

(ii) 150 ng/J (1.2 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO_X plus CO in excess of either:

(i) 160 ng/J (1.3 lb/MWh) gross energy output; or

(ii) 170 ng/J (1.4 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_X plus CO in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

■ 17. Section 60.47Da is amended as follows:

■ a. By revising paragraph (c).

■ b. By adding paragraph (f).

■ c. By adding paragraph (g).

■ d. By adding paragraph (h).

■ e. By adding paragraph (i).

§ 60.47Da Commercial demonstration permit.

* * * * *

(c) An owner or operator of an affected facility that uses fluidized bed combustion (atmospheric or pressurized) and 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.

* * * * *

(f) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the total PM emission reduction requirements under § 60.42Da but must, as a minimum, reduce PM emissions to less than 6.4 ng/J (0.015 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 standards or emission reduction requirements under § 60.43Da but must, as a minimum, reduce SO_2 emissions to 5 percent of the potential combustion concentration (95 percent reduction) or to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(h) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions control system or advanced combustion controls who is issued a commercial demonstration permit by the Administrator is not subject to the NO_X standards or emission reduction requirements under § 60.44Da but must, as a minimum, reduce NO_X emissions to less than 130 ng/J (1.0 lb/MWh) or the combined NO_X plus CO emissions to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(i) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category listed in the following table.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	SO_2	1,000

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	NO_X	1,000
Multi-pollutant Emission Control	PM	1,000
Pressurized Fluidized Bed Combustion	SO_2	1,000
Pressurized Fluidized Bed Combustion	NO_X	1,000
Pressurized Fluidized Bed Combustion	PM	1,000
Advanced Combustion Controls	NO_X	1,000

■ 18. Section 60.48Da is amended as follows:

■ a. By revising paragraphs (a) through (g).
■ b. By revising paragraph (i).
■ c. By revising paragraph (k)(1)(i).
■ d. By revising paragraph (k)(2)(i).
■ e. By revising paragraph (k)(2)(iv).
■ f. By removing and reserving paragraph (l).
■ g. By revising paragraph (m).
■ h. By revising paragraph (n).
■ i. By revising paragraphs (p)(5), (7), and (8).
■ j. By adding paragraph (r).
■ k. By adding paragraph (s).

§ 60.48Da Compliance provisions.

(a) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, the applicable PM emissions limit and opacity standard under § 60.42Da, SO_2 emissions limit under § 60.43Da, and NO_X emissions limit under § 60.44Da apply at all times except during periods of startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, the applicable SO_2 emissions limit under § 60.43Da, NO_X emissions limit under § 60.44Da, and NO_X plus CO emissions limit under § 60.45Da apply at all times. The applicable PM emissions limit and opacity standard under § 60.42Da apply at all times except during periods of startup and shutdown.

(b) After the initial performance test required under § 60.8, compliance with the applicable SO_2 emissions limit and percentage reduction requirements under § 60.43Da, NO_X emissions limit under § 60.44Da, and NO_X plus CO emissions limit under § 60.45Da 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-boiler operating day rolling average emission rate for both SO_2, NO_X or NO_X plus CO as applicable, and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards.

(c) For the initial performance test required under § 60.8, compliance with the applicable SO_2 emissions limits and percentage reduction requirements under § 60.43Da, the NO_X emissions limits under § 60.44Da, and the NO_X plus CO emissions limits under § 60.45Da is based on the average emission rates for SO_2, NO_X, CO, 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.

(d) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NO_X emissions limits 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, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NO_X emissions limits is determined by dividing the sum of the SO_2 and NO_X emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

(e) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, 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. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable SO_2 percentage reduction requirements is determined based on the "as fired" total potential emissions and the total outlet SO_2 emissions for the 30 successive boiler operating days.

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable daily average PM emissions limits 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. Daily averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable daily average PM emissions limits is determined by dividing the sum of the PM emissions for the 30 successive boiler operating days by the sum of the gross useful output or net energy output, as applicable, for the 30 successive boiler operating days.

(g) For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average NO_X plus CO emissions limit is determined by dividing the sum of the NO_X plus CO emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as

applicable, for the 30 successive boiler operating days.

* * * * *

(i) Compliance provisions for sources subject to § 60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), (f), or (g). The owner or operator shall calculate NO_X emissions as 1.194×10^{-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)) or the average hourly net energy output, as applicable. 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)) or the average hourly net energy output, as applicable.

(k) * * *

(l) * * *

(i) The emission rate (E) of NO_X shall be computed using Equation 2 in this section:

$$E = \frac{(Csg \times Qsg) - (Cte \times Qte)}{(Osg \times h)} \quad \textbf{(Eq. 2)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

C_{te} = 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/h (dscf/h);

Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/h (dscf/h);

O_{sg} = Average hourly gross energy output from steam generating unit, J/h (MW); 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.

* * * * *

(2) * * *

(i) The emission rate (E) of NO_X shall be computed using Equation 3 in this section:

$$E = \frac{(Csg \times Qsg)}{Occ} \quad \textbf{(Eq. 3)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy 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/h (dscf/h); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(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/h) 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:

$$E = \frac{(ERsg \times Hcc)}{Occ} \quad \textbf{(Eq. 4)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy 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/h (MMBtu/h); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(m) Compliance provisions for sources subject to § 60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), (j)(3)(i), (l)(1)(i), (l)(1)(ii), or (l)(2). The owner or operator shall calculate SO_2 emissions as 1.660×10^{-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)) or the average hourly net energy output, as applicable. 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)) or the average hourly net energy output, as applicable.

(n) Compliance provisions for sources subject to § 60.42Da(c)(1) or (e)(1)(i). The owner or operator 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) or § 60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions

of § 60.49Da(k)) or the average hourly net energy output, as applicable.

* * * * *

(p) * * *

(5) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-boiler operating day rolling average basis. Beginning on January 1, 2012, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

* * * * *

(7) All non-out-of-control 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, non-out-of-control emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-boiler operating day rolling average.

* * * * *

(r) Compliance provisions for sources subject to § 60.45Da. To determine compliance with the NO_X plus CO emissions limit, the owner or operator shall use the procedures specified in paragraphs (r)(1) through (3) of this section.

(1) Calculate NO_X emissions as 1.194×10^{-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)) or the average hourly net energy output, as applicable.

(2) Calculate CO emissions by multiplying the average hourly CO output concentration (measured according to the provisions of § 60.49Da(u), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(3) Calculate NO_X plus CO emissions by summing the NO_X emissions results from paragraph (r)(1) of this section plus the CO emissions results from paragraph (r)(2) of this section.

(s) Affirmative defense for exceedance of emissions limit during malfunction. In response to an action to enforce the standards set forth in paragraph §§ 60.42Da, 60.43Da, 60.44Da, and 60.45Da, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense as specified in paragraphs (s)(1) and (2) of this section. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (s)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

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

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

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

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

(ii) Repairs were made as expeditiously as possible when the applicable emissions limits were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount, and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

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

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

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

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

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

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

(2) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (s)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

■ 19. Section 60.49Da is amended as follows:

■ a. By revising paragraphs (a)(1) and (2).

■ b. By revising paragraph (a)(3) introductory text.
■ c. By revising paragraph (a)(3)(ii).
■ d. By revising paragraph (a)(3)(iii)(B).
■ e. By adding paragraph (a)(4).
■ f. By revising paragraph (b) introductory text.
■ g. By revising paragraph (b)(2).
■ h. By revising paragraph (e).
■ i. By revising paragraph (k) introductory text.
■ j. By revising paragraph (k)(3).
■ k. By revising paragraph (l).
■ l. By removing and reserving paragraph (p).
■ m. By removing and reserving paragraph (q).
■ n. By removing and reserving paragraph (r).
■ o. By revising paragraph (t).
■ p. By revising paragraph (u)(1)(iii).
■ q. By revising paragraph (v)(4).

§ 60.49Da Emission monitoring.

(a) * * *

(1) Except as provided for in paragraphs (a)(2) and (4) of this section, the owner or operator of an affected facility subject to an opacity standard, shall install, calibrate, maintain, and operate a COMS, 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).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), (iii), or (iv) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in § 60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs § 60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) 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 emissions of SO_2 or PM;

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section.

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO_2, or CO emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section; or

(iv) The affected facility uses an ESP and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part.

(3) The owner or operator of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to using a COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section. The opacity performance test requirement in paragraph (a)(3)(i) must be conducted by April 29, 2011, within 45 days after stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later.

* * * * *

(ii) Except as provided in paragraph (a)(3)(iii) or (iv) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a)(3)(i) of this section according to the applicable schedule in paragraphs (a)(3)(ii)(A) through (a)(3)(ii)(C) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(C) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(iii) * * *

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(4) An owner or operator of an affected facility that is subject to an opacity standard under § 60.42a(b) is not required to operate a COMS provided that affected facility meets the conditions in either paragraph (a)(4)(i) or (ii) of this section.

(i) The affected facility combusts only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.51a(d).

(ii) The owner or operator of the affected facility installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, except where natural gas and/or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/

MMBtu) or less are the only fuels combusted, as follows:

* * * * *

(2) For a facility that qualifies under the numerical limit provisions of § 60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere.

* * * * *

(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, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross energy output for sources demonstrating compliance with an output-based standard.

* * * * *

(3) For an affected facility generating process steam in combination with electrical generation, the gross energy output is determined according to the definition of "gross energy output" specified in § 60.41Da that is applicable to the affected facility.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard 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 calibration drift (CD) assessment, relative accuracy test audit (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

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da 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 facility demonstrating compliance with the input-based emissions limit in § 60.42Da may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) * * *

(1) * * *

(iii) At a minimum, non-out-of-control 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-boiler operating day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

* * * * *

(v) * * *

(4) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFire database.

* * * * *

■ 20. Section 60.50Da is amended as follows:

■ a. By revising paragraph (b).

■ b. By removing paragraph (g).

■ c. By removing paragraph (h).

■ d. By removing paragraph (i).

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(b) In conducting the performance tests to determine compliance with the PM emissions limits in § 60.42Da, the owner or operator shall meet the requirements specified in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator shall measure filterable PM to determine compliance with the applicable PM emissions limit in § 60.42Da as specified in paragraphs (b)(1)(i) through (ii) of this section.

(i) 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.

(ii) For the PM concentration, Method 5 of appendix A of this part shall be used for an affected facility that does not use a wet FGD. For an affected facility that uses a wet FGD, Method 5B of appendix A of this part shall be used downstream of the wet FGD.

(A) 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).

(B) 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.

(2) In conjunction with a performance test performed according to the requirements in paragraph (b)(1) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall measure condensable PM using Method 202 of appendix M of part 51.

(3) Method 9 of appendix A of this part and the procedures in § 60.11 shall be used to determine opacity.

* * * * *

■ 21. Section 60.51Da is amended as follows:

■ a. By revising paragraph (a).

■ b. By revising paragraph (b)(5).

■ c. By revising paragraph (d).

■ d. By removing and reserving paragraph (g).

■ e. By revising paragraph (k).

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and NO_X plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) must be reported to the Administrator.

(b) * * *

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

* * * * *

(d) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) and conducting performance tests using Method 9 of appendix A–4 of this part shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraph (d)(1) of this section.

(1) For each performance test conducted using Method 9 of appendix

A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets.

(2) [Reserved]

* * * * *

(k) 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 (b) 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.

§ 60.52Da [Amended]

■ 22. Section 60.52Da is amended by removing and reserving paragraph (a).

Subpart Db—[Amended]

■ 23. Section 60.40b is amended as follows:

■ a. By revising paragraph (c).
■ b. By revising paragraph (h).
■ c. By revising paragraph (i).
■ d. By adding paragraph (l).
■ e. By adding paragraph (m).

§ 60.40b Applicability and delegation of authority.

* * * * *

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_x standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

* * * * *

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (*i.e.*, heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* 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 stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

* * * * *

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_x standards under this subpart and the PM standards under subpart BB.

(m) Temporary boilers are not subject to this subpart.

24. Section 60.41b is amended by revising the definition of "distillate oil", and adding the definition of "temporary boiler" in alphabetical order to read as follows:

§ 60.41b Definitions.

* * * * *

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), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

* * * * *

■ 25. Section 60.43b is amended by revising paragraph (f) to read as follows:

§ 60.43b Standard for particulate matter (PM).

* * * * *

(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. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

* * * * *

■ 26. Section 60.44b is amended as follows:

■ a. The section heading is revised.
■ b. By revising paragraph (b) introductory text.
■ c. By revising paragraph (c).
■ d. By revising paragraph (d).
■ e. By revising paragraph (e).
■ f. By revising paragraph (l)(1).

§ 60.44b Standard for nitrogen oxides (NO_x).

* * * * *

(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 only 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:

* * * * *

(c) Except as provided under paragraph (d) 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 coal or oil, natural gas (or any combination of the three), and wood, 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, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with 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, natural gas (or any combination of the three).

(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 and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less 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, distillate oil, or a mixture of these fuels 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, distillate oil, or a mixture of these fuels.

(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 only 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:

* * * * *

(l) * * *

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with 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 any combination of the three); or

* * * * *

■ 27. Section 60.46b is amended by revising paragraph (j)(14) to read as follows:

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

* * * * *

(j) * * *

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

■ 28. Section 60.48b is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraphs (a)(1)(i) through (iii) .

■ c. By revising paragraph (a)(2)(ii).

■ d. By revising paragraph (j) introductory text.

■ e. By revising paragraph (j)(5).

■ f. By revising paragraph (j)(6).

■ g. By adding paragraph (j)(7).

■ h. By adding paragraph (l).

§ 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 continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(2) * * *

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an

opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

* * * * *

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) 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 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.

* * * * *

(l) An owner or operator of an affected facility that is subject to an opacity standard under § 60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.49b(h).

■ 29. Section 60.49b is amended by revising paragraph (r)(1) to read as follows.

§ 60.49b Reporting and recordkeeping requirements.

* * * * *

(r) * * *

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas 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, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

* * * * *

Subpart Dc—[Amended]

■ 30. Section 60.40c is amended as follows:

■ a. By revising paragraph (a).

■ b. By revising paragraph (e).

■ c. By revising paragraph (f).

■ d. By revising paragraph (g).

■ e. By adding paragraph (h).

■ f. By adding paragraph (i).

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) 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/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

* * * * *

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, 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.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

■ 31. Section 60.41c is amended as follows:

■ a. By removing the definition of "Cogeneration."

■ b. By revising the definition of "Distillate oil."

■ c. By adding a definition of "Temporary boiler" in alphabetical order.

§ 60.41c Definitions.

* * * * *

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), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

* * * * *

■ 32. Section 60.42c is amended as follows:

■ a. By revising paragraph (c)(1) and (3).

■ b. By revising paragraph (d).

■ c. By revising paragraph (e)(1)(ii).

■ d. By revising paragraph (h) introductory text.

■ e. By revising paragraph (h)(3).

■ f. By adding paragraph (h)(4).

§ 60.42c Standard for sulfur dioxide (SO_2).

* * * * *

(c) * * *

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

* * * * *

(3) Affected facilities located in a noncontinental area; or

* * * * *

(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 from oil; 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) * * *

(1) * * *

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

* * * * *

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) 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.

* * * * *

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

* * * * *

■ 33. Section 60.43c is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraph (b) introductory text.

■ c. By revising paragraph (c).

■ d. By revising paragraphs (e)(1), (3), and (4).

§ 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/h) 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:

* * * * *

(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/h) 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:

* * * * *

(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/h) 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. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

* * * * *

(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/h) 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.

* * * * *

(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/h) 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) 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.

■ 34. Section 60.45c is amended as follows:

■ a. By revising paragraph (c)(14).

■ b. By revising paragraph (d).

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

* * * * *

(c) * * *

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(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/h).

■ 35. Section 60.47c is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraphs (a)(1)(i) through (iii).

■ c. By revising paragraph (a)(2)(ii).

■ d. By revising paragraph (f).

■ e. By removing paragraph (g).

§ 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 continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(2) * * *

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

Subpart HHHH—[Removed and Reserved]

■ 36. Subpart HHHH is removed and reserved.

PART 63—[AMENDED]

■ 37. The authority citation for 40 CFR Part 63 continues to read as follows:

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

Subpart A—[Amended]

■ 38. Section 63.14 is amended as follows:

■ a. By adding paragraphs (b)(19) and (20).

■ b. By adding paragraphs (b)(22) and (23).

■ c. By adding paragraphs (b)(69) through (72).

■ d. By revising paragraph (i)(1).

§ 63.14 Incorporation by reference.

* * * * *

(b) * * *

(19) ASTM D95–05 (Reapproved 2010), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, approved May 1, 2010, IBR approved for § 63.10005(i)(4)(i).

(20) ASTM Method D388–05, Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for § 63.10042.

* * * * *

(22) ASTM Method D396–10, Standard Specification for Fuel Oils, including Appendix X1, approved October 1, 2010, IBR approved for § 63.10042.

(23) ASTM D4006–11, Standard Test Method for Water in Crude Oil by Distillation, including Annex A1 and Appendix X1, approved June 1, 2011, IBR approved for § 63.10005(i)(4)(ii).

* * * * *

(69) ASTM D4057–06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, including Annex A1, approved June 1, 2011, IBR approved for § 63.10005(i)(4)(iv).

(70) ASTM D4177–95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, including Annexes A1 through A6 and Appendices X1 and X2, approved May 1, 2010, IBR approved for § 63.10005(i)(4)(iii).

(71) ASTM D6348–03 (Reapproved 2010), Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, including Annexes A1 through A8, approved October 1, 2010, IBR approved for table 1 to subpart UUUUU of this part, table 2 to subpart UUUUU of this part, table 5 to subpart UUUUU of this part, and appendix B to subpart UUUUU of this part.

(72) ASTM D6784–02 (Reapproved 2008), Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 5 to subpart UUUUU of this part, and appendix A to subpart UUUUU of this part.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus]," IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), table 5 to subpart DDDDD of this part, table 1 to subpart ZZZZZ of this part, table 4 to subpart JJJJJJ of this part, and table 5 to subpart UUUUU of this part.

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■ 39. Part 63 is amended by adding subpart UUUUU to read as follows:

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

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Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in § 63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in § 63.10042 of this subpart.

§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, and existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in 63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in 63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011, and you meet the applicability criteria at the time you commence construction.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after May 3, 2011, and you meet the applicability criteria at the time you commence reconstruction.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change process (*e.g.*, fuel or utilization) is considered to be an existing source under this subpart.

§ 63.9983 Are any EGUs not subject to this subpart?

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit, covered by 40 CFR part 63, subpart YYYY.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and combusts natural gas for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but did not fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year. Heat input means heat derived from combustion of fuel in an EGU 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 industrial boilers).

(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

§ 63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in § 63.10005(g).

(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.

(c) You must meet the notification requirements in § 63.10030 according to the schedule in § 63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.

(e) If you own or operate an electric steam generating unit that is exempted from this subpart under § 63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in § 63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.

(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.

§ 63.9985 What is a new EGU?

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.

(1) An EGU that commenced construction after May 3, 2011.

(2) An EGU that commenced reconstruction or modification after May 3, 2011.

(b) [Reserved]

Emission Limitations and Work Practice Standards

§ 63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in § 63.10042.

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and

(2) EGUs designed for low rank virgin coal.

(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in § 63.10042.

(1) Continental liquid oil-fired EGUs

(2) Non-continental liquid oil-fired EGUs,

(3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under § 63.10009.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

(b) As provided in § 63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.

(c) You may use the alternate SO_2 limit in Tables 1 and 2 to this subpart only if your coal-fired EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and SO_2 continuous emissions monitoring system (CEMS) installed on the unit; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology installed on the unit consistent with § 63.10000(b).

General Compliance Requirements

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)(1) For coal-fired units and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct the initial performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a low emitting EGU (LEE) for one or more applicable emissions limits, with two exceptions:

(A) You may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration, and

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-fired fuel fired EGU or IGCC EGU is new.

(ii) For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status.

(iii) For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(iv) If your coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or compliance performance testing repeated quarterly.

(A) If you elect to use PM CPMS, you will establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply: total non-mercury HAP metals, individual non-mercury HAP metals or filterable PM. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. If you elect to use a PM CPMS, you must repeat the performance test annually for the selected pollutant limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(B) You may also opt to install and operate a particulate matter CEMS certified in accordance with Performance Specification 11 and Procedure 2 of 40 CFR part 60, Appendices B and F, respectively, in accordance with § 63.10010(i).

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO_2) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO_2 emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your existing liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or performance testing conducted quarterly.

(A) If you elect to use PM CPMS, you will establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply: total HAP metals, individual HAP metals, or filterable PM. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. If you elect to use a PM CPMS, you must repeat the performance test at least annually for the selected pollutant limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(B) If you elect to use a PM CEMS, you will use the CEMS in accordance with § 63.10010(i) to demonstrate initial and continuous compliance with the filterable PM emission limit.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance by conducting periodic quarterly performance stack tests for HCl and HF. If you elect to demonstrate compliance through quarterly performance testing, then you must also develop a site-specific monitoring plan to ensure that the operations of the unit remain consistent with those during the performance test. As another alternative, you may measure or obtain, and keep

records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in § 63.10042, then you are not subject to the emission limits in Tables 1 and 2, but must comply with the performance tune-up work practice requirements in Table 3.

(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B to part 60 or part 75 of this chapter, and that meet the requirements of § 63.10010. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.

(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of § 63.10010 (*e.g.*, if the CMS was previously certified under another program).

(4) You must operate and maintain the CMS according to the site-specific monitoring plan.

(5) The provisions of the site-specific monitoring plan must address the following items:

(i) Installation of the CEMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device). See § 63.10010(a) for further details. For CPMS installations, follow the procedures in § 63.10010(h).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Schedule for conducting initial and periodic performance evaluations.

(iv) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations), including ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d).

(v) On-going operation and maintenance procedures, in accordance with the general requirements of §§ 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(vi) Conditions that define a CMS that is out of control consistent with § 63.8(c)(7)(i) and for responding to out of control periods consistent with §§ 63.8(c)(7)(ii) and (c)(8).

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§ 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.

(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to § 63.10021(e).

(f) You are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (*e.g.*, 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless you are a solid waste incineration unit subject to standards under CAA section 129 (*e.g.*, 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or Subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

(g) If you no longer meet the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that you last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with § 63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

(h)(1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.

(2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

(ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory

currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;

(iii) The date on which you became subject to the currently applicable emission limits;

(iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.

(i)(1) If you own or operate an EGU subject to this subpart, and it has been at least 6 months since you operated in a manner that caused you to meet the definition of an EGU subject to this subpart, you may, consistent with paragraph (g) of this section, select the date on which your EGU will no longer be subject to this subpart. You must be in compliance with any newly applicable section 112 or 129 standards on the date you selected.

(2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;

(ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;

(iii) The date on which you became subject to this subpart;

(iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.

(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§ 63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§ 63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.

§ 63.10001 Affirmative defense for exceedence of emission limit during malfunction.

In response to an action to enforce the standards set forth in § 63.9991 you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

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

(1) The excess emissions:

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

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

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

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

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

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

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

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

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

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

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

(b) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report

within 45 days of the initial occurrence of the exceedance.

Testing and Initial Compliance Requirements

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of hourly electrical load data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the applicable date in paragraph (f) of this section for tune-up work practices for existing EGUs, in § 63.9984 for other requirements for existing EGUs, and in paragraph (g) of this section for all requirements for new EGUs.

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.*, an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test consists of 30 boiler operating days of data collected by the initial compliance demonstration date specified in § 63.10005 with the certified monitoring system.

(i) The 30-boiler operating day CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 1 or 2 to this subpart.

(ii) If you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the performance test period.

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to § 63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in § 63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in § 63.9984;

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid data CMS data recorded in the 30 boiler operating days immediately preceding that date;

(3) The performance test was conducted in accordance with all applicable requirements in § 63.10007 and Table 5 to this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly electrical loads) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.

(c) *Operating limits.* In accordance with § 63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) *CMS requirements.* If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§ 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO_2, HCl, or HF emissions limit in Table 1 or 2 of this subpart through use of an SO_2, HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 of this subpart through use of a PM CEMS installed, certified, and operated in accordance with § 63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see § 63.10007(e)), meets the applicable SO_2, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19–19 of Method 19 in appendix A–7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (Note: for this calculation, the term E_{hj} in Equation 19–19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply.

(iii) You must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this

subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984 for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponding to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.

(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) *Tune-ups.* All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to § 63.10021(e).

(f) For existing affected sources a tune-up may occur prior to April 16, 2012, so that existing sources without neural networks have up to 42 calendar months (3 years from promulgation plus 180 days) or, in the case of units employing neural network combustion controls, up to 54 calendar months (48 months from promulgation plus 180 days) after the date that is specified for your source in § 63.9984 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 9 to this subpart to demonstrate compliance with this requirement. If a tune-up occurs prior to such date, the source must maintain adequate records to show that the tune-up met the requirements of this standard.

(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may not pursue this compliance option if your existing EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration.

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in § 63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in § 63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30-boiler operating day performance test using Method 30B in appendix A–8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A–1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures), under all process operating conditions. You may use a pair of sorbent traps to sample the stack gas for no more than 10 days.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO_2 or O_2) data, using either Method 3A in appendix A–3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A–1 and A–2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A–1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from § 75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly electrical load data (megawatts), from facility records.

(ii) If you use CEMS to measure CO_2 (or O_2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one

representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in $\mu g/m^3$ (dry basis), for the 30-boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and electrical load for the test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in § 63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A–3 and A–4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values "C_h", "Q_h", "B_{ws}" and "$(MW)_h$" with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(*1*) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^6 to convert it to TBtu/hr; or

(*2*) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^3 to convert it to GW; or

(*3*) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (i.e., either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) Liquid-oil fuel moisture measurement. If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95–05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or

(ii) ASTM D4006–11, "Standard Test Method for Water in Crude Oil by Distillation," including Annex A1 and Appendix A1, or

(iii) ASTM D4177–95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," including Annexes A1 through A6 and Appendices X1 and X2, or

(iv) ASTM D4057–06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," including Annex A1.

(5) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in § 63.10000(c)(2)(iii) or

(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in § 63.10030.

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel- and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and § 63.10007 at least every year.

(b) For affected units meeting the LEE requirements of § 63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and § 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:

(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1).

(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, you must conduct Hg emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1). You must have 3 calendar years of testing and CEMS or

sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emission limit, for liquid oil-fired EGUs, you must conduct all applicable periodic emissions tests for filterable PM, or individual or total HAP metals emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in § 63.10000(c)(2)(iii).

(f) Unless you follow the requirements listed in paragraphs (g) and (h) of this section, performance tests required at least every 3 calendar years must be completed within 35 to 37 calendar months after the previous performance test; performance tests required at least every year must be completed within 11 to 13 calendar months after the previous performance test; and performance tests required at least quarterly must be completed within 80 to 100 calendar days after the previous performance test, except as otherwise provided in § 63.10021(d)(1).

(g) If you elect to demonstrate compliance using emissions averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to § 63.10021(e).

(1) For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 36 calendar months after the previous performance tune-up.

(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 48 calendar months after the previous performance tune-up.

(j) You must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in § 63.10031.

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to § 63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(1) If you use CEMS (Hg, HCl, SO_2, or other) to determine compliance with a 30-boiler operating day rolling average emission limit, you must collect data for all nonexempt unit operating conditions (see § 63.10011(g) and Table 3 to this subpart).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (*e.g.*, quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose to comply with the filterable PM emission limit and demonstrate continuous performance using a PM CPMS for an applicable emission limit as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b)(5) and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (*e.g.*, laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (*e.g.*, analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in

sections 12.2 and 12.3 of EPA Method 19 in appendix A–7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19–2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO_2 ppm by 1.66×10^{-7};

(ii) Multiply HCl ppm by 9.43×10^{-8};

(iii) Multiply HF ppm by 5.18×10^{-8};

(iv) Multiply HAP metals concentrations (mg/dscm) by 6.24×10^{-8}; and

(v) Multiply Hg concentrations (μg/scm) by 6.24×10^{-11}.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A–2 or A–3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A–2 or A–3, replacing the value of K with 1.66×10^{-7} lb/scf-ppm for SO_2, 9.43×10^{-8} lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18×10^{-8} lb/scf-ppm for HF (if an HF CEMS is used), or 6.24×10^{-8} lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining C_h as the average SO_2, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§ 63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A–4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10^3 term from Equation A–4 to determine the pollutant emission rate in lb/MWh.

(f) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.

§ 63.10008 [Reserved]

§ 63.10009 May I use emissions averaging to comply with this subpart?

(a) *General eligibility.* (1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of § 63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance.

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory are equal to or less than 1.0 lb/TBtu or 1.1E–2 lb/GWh or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2, according to the procedures in this section. Note that except for Hg emissions from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance testing. The averaging time for emissions averaging for Hg from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90 days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance testing. For the purposes of this paragraph, 30- (or 90-day) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group has operated 30 (or 90) days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross electrical output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) *Equations.* Use the following equations when performing calculations for your EGU emissions averaging group:

(1) *Group eligibility equations.*

$$WAERm = \frac{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Herm_i \times Rmm_i)\right]_p\right] + \sum_{i=1}^{m}(Ter_i \times Rmt_i)}{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n} Rmm_i\right]_p\right] + \sum_{i=1}^{m} Rmt_i} \quad (Eq.\ 1a)$$

Where:

WAERm = Weighted average emissions rate maximum in terms of lb/heat input or lb/gross electrical output,

$Herm_i$ = Hourly emissions rate (*e.g.*, lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring for hour i,

Rmm_i = Maximum rated heat input or gross electrical output of unit i in terms of heat input or gross electrical output,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent test of unit i in terms of lb/heat input or lb/gross electrical output,

Rmt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAERm = \frac{[\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Herm_i \times Smm_i \times Cfm_i)]_p] + \Sigma_{i=1}^{m}(Ter_i \times Smt_i \times Cft_i)}{[\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}Smm_i \times Cfm_i]_p] + \Sigma_{i=1}^{m}Smt_i \times Cft_i} \quad (Eq.\ 1b)$$

Where:

variables with similar names share the descriptions for Equation 1a,

Smm_i = maximum steam generation in units of pounds from unit i that uses CEMS or sorbent trap monitoring,

Cfm_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring,

Smt_i = maximum steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(2) Weighted 30-day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30-day rolling average emissions daily.

$$WAER = \frac{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Her_i \times Rm_i)]_p + \Sigma_{i=1}^{m}(Ter_i \times Rt_i)}{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Rm_i)]_p + \Sigma_{i=1}^{m}Rt_i} \quad (Eq.\ 2a)$$

Where:

Her_i = hourly emission rate (*e.g.*, lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)]_p + \Sigma_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Sm_i \times Cfm_i)]_p + \Sigma_{i=1}^{m}St_i \times Cft_i} \quad (Eq.\ 2b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS from the preceding 30-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Her_i \times Rm_i)]_p + \Sigma_{i=1}^{m}(Ter_i \times Rt_i)}{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Rm_i)]_p + \Sigma_{i=1}^{m}Rt_i} \quad (Eq.\ 3a)$$

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)]_p + \Sigma_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\Sigma_{i=1}^{p}[\Sigma_{i=1}^{n}(Sm_i \times Cfm_i)]_p + \Sigma_{i=1}^{m}St_i \times Cft_i} \quad (Eq.\ 3b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(c) *Separate stack requirements.* For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or

(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified 180 days after April 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum normal operating load of each EGU and the results of the initial performance tests. For this demonstration and prior to submitting your emissions averaging plan, if requested, you must conduct required emissions monitoring for 30 days of boiler operation and any required manual performance testing to calculate an initial weighted average emissions rate in accordance with this section. Should the Administrator require approval, you must submit your proposed emissions averaging plan and supporting data at least 120 days before April 16, 2015. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross electrical output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of this section as an alternative to using Equation 1a of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 day rolling average (90 day rolling average for Hg) basis according to paragraphs (f)(1) through (3) of this section. The first averaging period begins on 30 (or 90 for Hg) days after February 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross electrical output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross electrical output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(h) *CEMS (or sorbent trap monitoring) use.* If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) *Emissions testing.* If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) *Emissions averaging plan.* You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

(ii) The process weighting parameter (heat input, gross electrical output, or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates

emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (*e.g.*, CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO_2, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in § 63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If the Administrator requests you to submit the plan for review and approval, you must submit a complete implementation plan at least 120 days before April 16, 2015. If the Administrator requests you to submit the plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (h)(1) of this section; and

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained.

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in § 63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (*e.g.*, in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.

(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) *Single unit-single stack configurations.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

(3) *Unit(s) utilizing common stack with non-affected unit(s).*

(i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

(4) *Unit with a main stack and a bypass stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack, or, if it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall install a CEMS only on the main stack and count bypass hours of deviation from the monitoring requirements.

(5) *Unit with a common control device with multiple stack or duct configuration.* If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap

monitoring systems in the single stack as described in paragraph (a)(1) of this section.

(6) *Unit with multiple parallel control devices with multiple stacks.* If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

(iii) Sum the products determined under paragraph (a)(5)(iii)(B) of this section; and

(iv) Divide the result obtained in paragraph (a)(5)(iii)(C) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

(b) If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.*, at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from § 75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).

(f)(1) If you use an SO_2 CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30 boiler operating days.

(4) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30-boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30 boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (*i.e.*, period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (*e.g.*, milliamps, PM concentration, raw data signal).

(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

(6) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(i) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions are not used in calculations (report any such periods in your annual deviation report);

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods are not used in calculations (report emissions or operating levels and report any such periods in your annual deviation report);

(iii) Any data recorded during periods of startup or shutdown.

(7) You must record and make available upon request results of PM CPMS system performance audits, as well as the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2 to this subpart.

(1) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A–3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ± 14°C (320° ± 25°F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh).

(2) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(j) You may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CEMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install and certify your HAP metals CEMS according to the procedures and requirements in you approved site specific test plan as required in § 63.7(e). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CEMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CEMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CEMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring

system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of HAP metals CEMS system performance audits, dates and duration of periods when the HAP metals CEMS is out of control to completion of the corrective actions necessary to return the HAP metals CEMS to operation consistent with your site-specific performance evaluation and quality control program plan.

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in § 63.10000(c)(2)(iii) and Table 7 to this subpart.

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired unit, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with Table 4 to this subpart, § 63.10007, and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.*, tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (*e.g.*, Hg or HCl) directly, the first 30-boiler operating day rolling average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For a unit that uses a CEMS to measure SO_2 or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or filterable PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in § 63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to § 63.10030(e).

(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, *i.e.*, the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements given in Table 3 for each coal-fired, liquid oil-fired, and solid oil-derived fuel-fired EGU.

Continuous Compliance Requirements

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown or monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.

(b) Except as otherwise provided in § 63.10020(c), if you use a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (*e.g.*, flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30-boiler operating day rolling average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n}\ (Eq.\ 8)$$

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30 boiler operating days.

(c) If you use a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (*e.g.*, milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n}\ (Eq.\ 9)$$

Where:

Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and

(3) Must conduct site-specific monitoring for a liquid oil-fired unit to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020(a).

(e) If you must conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section, perform the first tune-up as part of your initial compliance demonstration. Notwithstanding this requirement, you may delay the first burner inspection until the next scheduled unit outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO_X and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO_X and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO_X and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO_x in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups as follows:

(i) If the first required tune-up is performed as part of the initial compliance demonstration, report the date of the tune-up in hard copy (as specified in § 63.10030) and electronically (as specified in § 63.10031). Report the date of each subsequent tune-up electronically (as specified in § 63.10031).

(ii) If the first tune-up is not conducted as part of the initial compliance demonstration, but is postponed until the next unit outage, report the date of that tune-up and all subsequent tune-ups electronically, in accordance with § 63.10031.

(f) You must submit the reports required under § 63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in § 63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under § 63.10031.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to § 63.10031.

(h) You must keep records as specified in § 63.10032 during periods of startup and shutdown.

(i) You must provide reports as specified in § 63.10031 concerning activities and periods of startup and shutdown.

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (3) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (*e.g.*, milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (*e.g.*, nine 1-hour average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as the highest 1-hour average PM CPMS output value recorded during the performance test. You must verify an existing or establish a new operating limit after each repeated performance test.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in § 63.10011(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (7), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (*e.g.*, use of PM CPMS); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following:

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10006(i), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) "This EGU complies with the requirements in § 63.10021(a) to demonstrate continuous compliance." and

(B) "No secondary materials that are solid waste were combusted in any affected unit."

§ 63.10031 What reports must I submit and when?

(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.9984.

(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to § 63.10021(e). Include the date of the most recent burner inspection if it was not done annually and was delayed until the next scheduled unit shutdown.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in § 63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) As of January 1, 2012, and within 60 days after the date of completing each performance test, you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority

in the format specified by the delegated authority.

(1) Within 60 days after the date of completing each CEMS (SO_2, PM, HCl, HF, and Hg) performance evaluation test, as defined in § 63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in § 63.2 and as required in this chapter.

(2) For a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

(3) Reports for an SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and § 63.10021(f).

(4) Submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under § 63.10030(e) to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1), (2), and (3) of this section in paper format.

(g) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) For an EGU that qualifies as an LEE under § 63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with § 63.10009, you must additionally keep a copy of the emissions averaging implementation

plan required in § 63.10009(g), all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022.

(f) You must keep records of the occurrence and duration of each startup and/or shutdown.

(g) You must keep records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.

§ 63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.9991(a) and (b) under § 63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of "test method" in § 63.2.

(3) Approval of major changes to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 63.2 (the General Provisions), and in this section as follows:

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

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for the fuel to be combusted the entire 24-hour period.

Capacity factor for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered "coal" for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Coal refuse means any by-product 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 with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Cogeneration means a steam-generating unit that simultaneously produces both electrical and useful thermal (or mechanical) energy from the same primary energy source.

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of "fossil fuel-fired" or stationary, integrated gasification combined cycle:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent

of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396–10, "Standard Specification for Fuel Oils" (incorporated by reference, see § 63.14).

Dry flue gas desulfurization technology, or *dry FGD,* or *spray dryer absorber* (*SDA*), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO_2 and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (*e.g.*, conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO_2 and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Electric 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 integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (*e.g.*, emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO_2 in the exhaust gas stream.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 25 MW of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.*, coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Fluidized bed boiler, or *fluidized bed combustor,* or *circulating fluidized boiler,* or *CFB* means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the upward flow of air and combustion products.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the 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 output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), 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 or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015.

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Monitoring system malfunction or out of control period means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Non-continental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se). *Oil* means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (*e.g.*, petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Particulate matter or *PM* means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal (PC) boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396–10, "Standard Specification for Fuel Oils" (incorporated by reference, see § 63.14).

Responsible official means responsible official as defined in 40 CFR 70.2.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use), or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler.

Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use).

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

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 integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and

overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Unit designed for coal > 8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, *e.g.*, California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.*, Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or *wet FGD, or wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO_2 and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

Tables to Subpart UUUUU of Part 63

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	7.0E–3 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GW.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–3 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HC1)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR.		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–4 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	7.0E–3 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–3 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E–2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh[4] 9.0E–2 lb/MWh[5]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E–2 lb/GWh.	
	Arsenic (As)	2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	4.0E–2 lb/GWh.	
	Cobalt (Co)	4.0E–3 lb/GWh.	
	Lead (Pb)	9.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO^2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR Total HAP metals	OR 7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	
	Lead (Pb)	3.0E–2 lb/GWh.	
	Manganese (Mn)	1.0E–1 lb/GWh.	
	Nickel (Ni)	4.1E–0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour
	c. Hydrogen fluoride (HF)	5.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit ...	a. Filterable particulate matter (PM).	2.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR Total non-Hg HAP metals	OR 6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross electric output.
[2] Incorporated by reference, see § 63.14.
[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.
[4] Duct burners on syngas; gross electric output.
[5] Duct burners on natural gas; gross electric output

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table 5
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh ..	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in §63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Individual HAP metals:	.....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E–2 lb/GWh ..	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:	.....	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Cadmium (Cd)	1.5E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/MMBtu or 1.8E0 lb/MWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E–2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh ..	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		Collect a minimum of 1 dscm per run.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E–2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per Run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be)	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Mercury (Hg)	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	Hydrogen chloride (HCl)	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in §63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table 5
6. Solid oil-derived fuel-fired unit ..	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals	.....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–2 lb/TBtu or 6.0E–4 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 4.0E–3 lb/GWh.	
	Chromium (Cr)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Selenium (Se)	1.2E0 lb/TBtu 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	3.0E–1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or Sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.

[2] Gross electric output.

[3] Incorporated by reference, see §63.14.

[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS

[As stated in §§63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in §63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in §63.10021(e).
3. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during startup.	You must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels, either natural gas or distillate oil or a combination of clean fuels for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.10011(g) and §63.10021(h) and (i).

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS—Continued

[As stated in §§ 63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
4. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use) or at the point of no fuel being fired in the boiler. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler. During shutdown, you must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

TABLE 4 TO SUBPART UUUUU OF PART 63—OPERATING LIMITS FOR EGUS

[As stated in § 63.9991, you must comply with the applicable operating limits]

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2] . . .
1. Filterable Particulate matter (PM).	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Method 5 at Appendix A–3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at Appendix A–3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 front half temperature shall be 160 ° ± 14 °C (320 ° ± 25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR PM CEMS	OR a. Install, certify, operate, and maintain the PM CEMS.	Performance Specification 11 at Appendix B to part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals.	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2] . . .
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration.	Method 29 at Appendix A–8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at Appendix A–8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF).	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the HCl and HF emissions concentrations.	Method 26 or Method 26A at Appendix A–8 to part 60 of this chapter or Method 320 at Appendix A to part 63 of this chapter or ASTM 6348–03 [3] with (1) additional quality assurance measures in footnote [4] and (2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR HCl and/or HF CEMS	OR a. Install, certify, operate, and maintain the HCl or HF CEMS.	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter or Method 30B at Appendix A–8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–1 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A–8 to part 60 of this chapter, ASTM D6784 [3], or Method 29 at Appendix A–8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2] . . .
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
		Hg CEMS	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		a. Install, certify, operate, and maintain the CEMS.	
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of Appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system.	a. Install, certify, operate, and maintain the sorbent trap monitoring system.	Sections 3.2.2 and 5.2 of Appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of Appendix A to this subpart.
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points.	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at Appendix A–1 to part 60 of this chapter or Method 30B at Appendix A–8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G, or 2H at Appendix A–1 or A–2 to part 60 of this chapter or flow monitoring system certified per Appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–1 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981,[3] or diluent gas monitoring systems certified according to Part 75 of this chapter.
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A–8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.*, per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per Appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 22.0 lb/year threshold.	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS.	Part 75 of this chapter and §§ 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and § 63.10021(h).

[2] See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.
[3] Incorporated by reference, see § 63.14.
[4] When using ASTM D6348–03, the following conditions must be met: (1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; (2) For ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≥ R ≤ 130%; and (4) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$Reported\ Result = \frac{(Measured\ Concentration\ in\ Stack)}{\%R} x\,100$$

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(g)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.*, milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the three run performance test. 3. Determine the highest 1-hour average PM CPMS measured during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

TABLE 7 TO SUBPART UUUUU OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

[As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following]

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30-boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the arithmetic 30-boiler operating day rolling average of all of the quality assured hourly average PM CPMS output data (*e.g.*, milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring for liquid oil-fired units for HCl and HF emission limit monitoring.	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired units to measure compliance with one or more applicable emissions limit in Table 1 or 2.	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.	Operating in accordance with Table 3.

TABLE 8 TO SUBPART UUUUU OF PART 63—REPORTING REQUIREMENTS

[As stated in § 63.10031, you must comply with the following requirements for reports]

You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.10031(c)(1) through (4); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e).	Semiannually according to the requirements in § 63.10031(b).

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c), (f)(2)–(3), (g), (h)(2)–(h)(9), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.7(a), (b), (c), (d), (e)(2)–(e)(9), (f), (g), and (h).	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS ...	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1), (c), (d)(1)–(2), (e), and (f)	Recordkeeping and Reporting Requirements ..	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii)–(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3), and (d)(3)–(5)	.....	No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions ..	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3)–(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9).	Reserved	No.

Appendix A to Subpart UUUUU—Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (*e.g.*, lb/TBtu or lb/GWh), regardless of speciation.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

2.1 *Monitoring System Installation Requirements.* Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, § 63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 *Primary and Backup Monitoring Systems.* In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, *i.e.*, when the system is "in control". However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 *Redundant Backup Systems.* A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on "hot standby" in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 *Non-redundant Backup Monitoring Systems.* A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on "cold standby" and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 *Temporary Like-kind Replacement Analyzers.* When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix "LK".

2.2.4 *Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.* To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the

unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (i.e., sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg^0, CAS Number 7439–97–6) and oxidized forms of Hg.

3.1 *Definitions.*

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg^{+2} to Hg^0 converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (µg/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST–Traceable Elemental Hg Standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators" or an interim version of that protocol.

3.1.5 *NIST–Traceable Source of Oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride ($HgCl_2$), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators" or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (i.e., low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit* or *RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 Quality Assurance *(QA) Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A–1. The CEMS in Figure A–1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

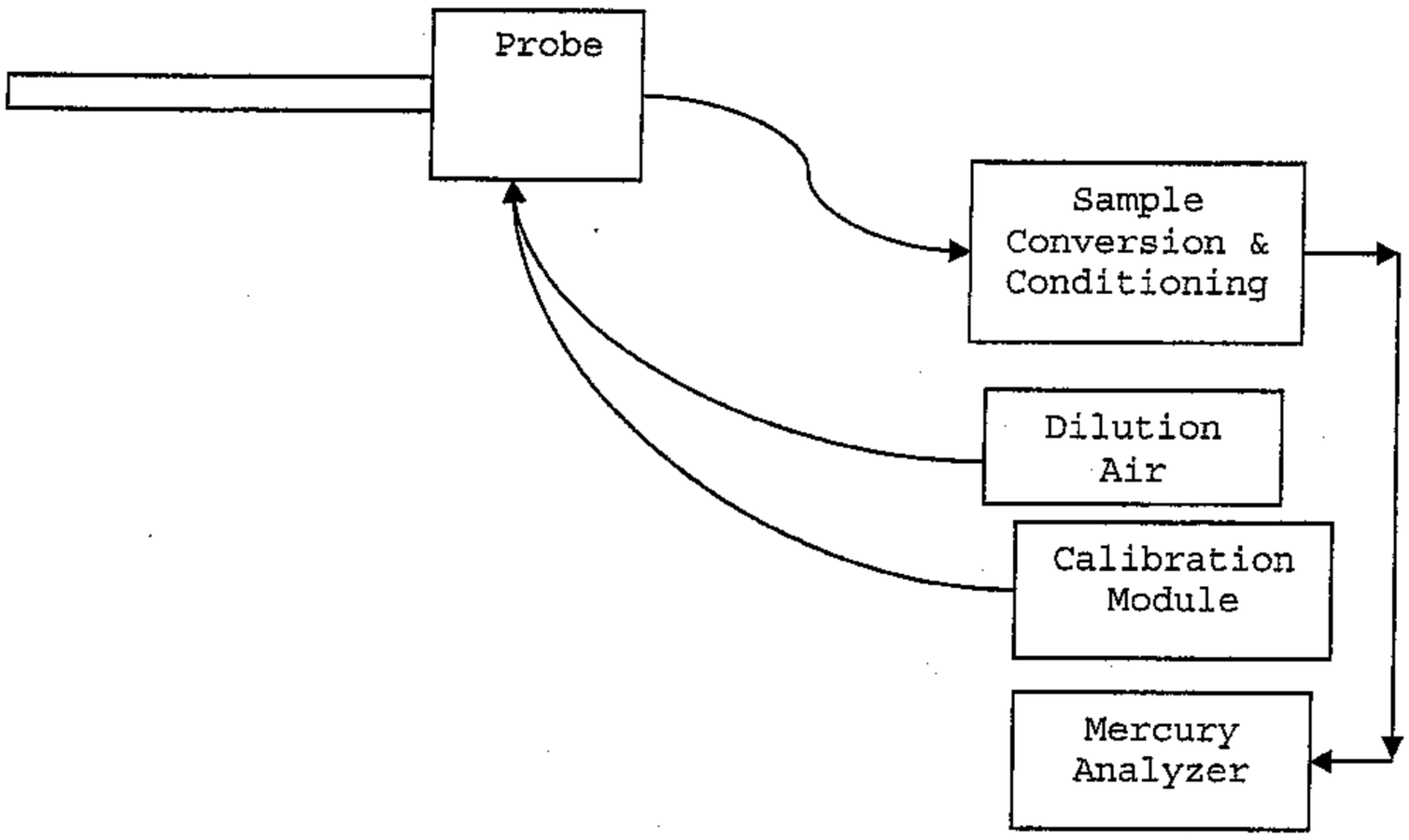


FIGURE A-1. TYPICAL MERCURY CEMS

3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg^{+2} to Hg^0 converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 *Sample Probe.* The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 *Filter or Other Particulate Removal Device.* The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 *Sample Line.* The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 *Conditioning Equipment.* For wet basis systems, such as the one shown in Figure A–1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A–1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s).* Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and $HgCl_2$ separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery.* The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer.* An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder.* A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards.*

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this section) shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (*e.g.*, NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

3.2.1.2.2 *Required Calibration Gas Concentrations.*

3.2.1.2.2.1 *Zero-Level Gas.* A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 *Low-Level Gas.* A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 *Mid-Level Gas.* A mid-level calibration gas with a Hg concentration of 50

to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 *High-Level Gas.* A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 *Installation and Measurement Location.* For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (i.e., a flow monitor, CO_2 or O_2 monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 *Monitor Span and Range Requirements.* Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 *Maximum Potential Concentration.* There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 μg/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 μg/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (*i.e.*, the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 *Span Value.* To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 μg/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 μg/scm; or the next highest multiple of 10 μg/scm.

3.2.1.4.3 *Analyzer Range.* The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

3.2.2 *Sorbent Trap Monitoring System.* A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 *Other Necessary Data Collection.* To convert measured hourly Hg concentrations to the units of the applicable emissions standard (*i.e.*, lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained, and quality-assured according to the applicable provisions of part 75 of this chapter (see §§ 63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 *Heat Input-Based Emission Limits.* For a heat input-based Hg emission limit (*i.e.*, in lb/TBtu), data from a certified CO_2 or O_2 monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

3.2.3.2 *Electrical Output-Based Emission Rates.* If the applicable Hg limit is electrical output-based (*i.e.*, lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 *Sorbent Trap Monitoring System Operation.* Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in § 63.10005(g).

4.1.1 *Hg CEMS.* Table A–1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (*i.e.*, combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Either elemental or oxidized NIST-traceable Hg standards (as defined in sections 3.1.4 and 3.1.5 of this appendix) may be used for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over nonconsecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.*, resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A–1. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.2 *Linearity Check.* Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A–1. The LE must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity

check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A–1. The SIE must either meet the main performance specification or the alternative specification in Table A–1. (**Note:** This test is not required if the CEMS does not have a converter).

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR Hg CEMS

For this required certification test . . .	The main performance specification[1] is . . .	The alternate performance specification[1] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test[2]	$\|R - A\| \leq 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days.	$\|R - A\| \leq 1.0$ µg/scm	The alternate specification may be used on any day of the test.
Linearity check[3]	$\|R - A_{avg}\| \leq 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high).	$\|R - A_{avg}\| \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check[4]	$\|R - A_{avg}\| \leq 10.0\%$ of the reference gas concentration at each calibration gas level.	$\|R - A_{avg}\| \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	$\|RM_{avg} - C_{avg}\| \leq 1.0$ µg/scm**	$RM_{avg} < 5.0$ µg/scm.
Cycle time test[2]	15 minutes.[5]		

[1] Note that $|R - A|$ is the absolute value of the difference between the reference gas value and the analyzer reading. $|R - A_{avg}|$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.
[2] Use either elemental or oxidized Hg standards; a mid-level or high-level upscale gas may be used. This test is not required for Hg CEMS that use integrated batch sampling; however, those monitors must be capable of recording at least one Hg concentration reading every 15 minutes.
[3] Use elemental Hg standards.
[4] Use oxidized Hg standards. Not required if the CEMS does not have a converter.
[5] Stability criteria—Readings change by <2.0% of span *or* by ≤0.5 µg/scm, for 2 minutes.
** Note that $|RM_{avg} - C_{avg}|$ is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between RM_{avg} and C_{avg} can be either + or −.

4.1.1.4 *Cycle Time Test.* Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784–02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see § 63.14) and Methods 29, 30A, and 30B in appendix A–8 to part 60. When Method 29 or ASTM D6784–02 is used, paired sampling trains are required. To validate a Method 29 or ASTM D6784–02 test run, calculate the relative deviation (RD) using Equation A–1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the average concentration is ≤ 1.0 µg/dscm, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the two Hg concentrations does not exceed 0.2 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \quad \text{(Eq. A-1)}$$

Where:

RD = Relative deviation between the Hg concentrations of samples "a" and "b" (percent)
C_a = Hg concentration of Hg sample "a" (µg/dscm)
C_b = Hg concentration of Hg sample "b" (µg/dscm)

4.1.1.5.1 *Special Considerations.* A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if Method 30A is used. If Method 29, Method 30B, or ASTM D6784–02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see § 63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784–02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in Appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.5.3 *Bias Adjustment.* Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 "The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap

monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 μg/dscm, ≤10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations ≤1 μg/dscm and >0.5 μg/dscm, ≤ 20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations ≤0.5 μg/dscm and >0.1 μg/dscm, ≤ 50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations ≤0.1μg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a μg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry.The main and alternative RATA performance specifications in Table A–1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 *Hg CEMS.*

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A–2, below. All tests must be performed with the affected unit(s) operating (*i.e.*, combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 *Test Frequency.* The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use either NIST-traceable elemental Hg standards or NIST-traceable oxidized Hg standards for these calibrations. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for "non-QA operating quarters". A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 If required, perform a single-level system integrity check weekly, *i.e.*, once every 7 operating days (see the third column in Table A–2).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, *i.e.*, once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 *Grace Periods.*

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A–2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 *Conditional Data Validation.* For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR Hg CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test	Daily	• Use either a mid- or high-level gas. • Use either elemental or oxidized Hg.	|R−A| ≤ 5.0% of span value. *or* |R−A| ≤ 1.0 μg/scm.

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR Hg CEMS—Continued

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Single-level system integrity check	Weekly [1]	• Calibrations are not required when the unit is not in operation. • Required only for systems with converters. • Use oxidized Hg—either mid- or high-level. • Not required if daily calibrations are done with a NIST-traceable source of oxidized Hg.	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas value. *or* $\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm.
Linearity check *or* 3-level system integrity check	Quarterly [3]	• Required in each "QA operating quarter" [2]—and no less than once every 4 calendar quarters. • 168 operating hour grace period available. • Use elemental Hg for linearity check. • Use oxidized Hg for system integrity check.	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas value, at each calibration gas level. *or* $\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm.
RATA	Annual [4]	• For system integrity check, CEMS must have a converter. • Test deadline may be extended for "non-QA operating quarters", up to a maximum of 8 quarters from the quarter of the previous test. • 720 operating hour grace period available.	20.0% RA. *or* $\lvert RM_{avg} - C_{avg} \rvert \leq 1.0$ µg/scm, *if* $RM_{avg} < 5.0$ µg/scm.

[1] "Weekly" means once every 7 operating days.
[2] A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.
[3] "Quarterly" means once every QA operating quarter.
[4] "Annual" means once every four QA operating quarters.

5.1.6 *Adjustment of Span.* If you discover that a span adjustment is needed (*e.g.*, if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B–1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, *i.e.*, once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A–4 for Hg CEMS shall apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B–1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§ 63.10010(b) through (d)).

5.4 *QA/QC Program Requirements.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be

recorded (*e.g.*, changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also Document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B–1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (*e.g.*, wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (*e.g.*, one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. Data Reduction and Calculations

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with § 60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (*i.e.*, flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in appendix A–7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24×10^{-11} to convert it from µg/scm to lb/scf. In cases where an appropriate F-factor is not listed in Table 19–2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average O_2 concentration is above 14.0% O_2 (19.0% for an IGCC) or the hourly average CO_2 concentration is below 5.0% CO_2 (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10^6 to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis. Use Equation 19–19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term E_{hj} in Equation 19–19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A–2 of this section (for wet-basis measurements of Hg concentration) or Equation A–3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h \qquad \text{(Equation A-2)}$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/µg-scf,

C_h = Hourly average Hg concentration, wet basis (µg/scm)

Q_h = Stack gas volumetric flow rate for the hour (scfh).

(**Note:** Use unadjusted flow rate values; bias adjustment is not required)

$$M_h = K C_h Q_h \left(1 - B_{ws}\right) \qquad \text{(Equation A-3)}$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/µg-scf.

C_h = Hourly average Hg concentration, dry basis (μg/dscm).
Q_h = Stack gas volumetric flow rate for the hour (scfh)
(**Note:** Use unadjusted flow rate values; bias adjustment is not required).
B_{ws} = Moisture fraction of the stack gas, expressed as a decimal (equal to % H_2O/100)

6.2.2.2 Use Equation A–4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h} x\,10^3 \qquad \text{(Equation A-4)}$$

Where:
E_{ho} = Electrical output-based Hg emission rate (lb/GWh).
M_h = Hg mass emission rate for the hour, from Equation A–2 or A–3 of this section, as applicable (lb/h).
$(MW)_h$ = Gross electrical load for the hour, in megawatts (MW).
10^3 = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable electrical output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30-boiler operating day rolling average basis. Use Equation A–5 of this section to calculate the Hg emission rate for each averaging period.

$$\overline{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \qquad \text{(Equation A-5)}$$

Where:
$\bar{E}_o$ = Hg emission rate for the averaging period (lb/GWh).
E_{ho} = Electrical output-based hourly Hg emission rate for unit or stack operating hour "h" in the averaging period, from Equation A–4 of this section (lb/GWh).
n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters (**Note:** Do *not* include non-operating hours with zero emission rates in the average).

7. Recordkeeping and Reporting

7.1 *Recordkeeping Provisions.* For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap monitoring system(s) and any other monitoring system(s) (*i.e.*, flow rate, diluent gas, or moisture systems) needed for routine operation of a sorbent trap monitoring system or to convert Hg concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall Document how the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.*, a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For Hg CEMS and sorbent trap monitoring systems, the monitoring plan shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for those systems under § 75.53 (g) of this chapter.

7.1.1.2.1 *Electronic.* The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; Hg monitor span and range information The electronic monitoring plan shall be evaluated and submitted using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

7.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the Hg monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 *Operating Parameter Records.* The owner or operator shall record the following information for each operating hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (μg/scm, rounded to three significant figures);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.4 *Hg Emissions Records (Sorbent Trap Monitoring Systems).* For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap

system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (μg/scm, rounded to three significant figures). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, *e.g.*, liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.5 *Stack Gas Volumetric Flow Rate Records.*

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

7.1.6 *Records of Stack Gas Moisture Content.*

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A–7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from § 75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

7.1.7 *Records of Diluent Gas (CO_2 or O_2) Concentration.*

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO_2 or O_2 concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO_2 or O_2 concentration records, as specified in § 75.57(g) of this chapter.

7.1.8 *Hg Emission Rate Records.* For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to three significant figures), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A–4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.9 *Certification and Quality Assurance Test Records.* For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;

7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B–1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59 of this chapter.

7.2 *Reporting Requirements.*

7.2.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with § 63.10030.

7.2.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 Submit the electronic and hard copy information in section 7.1.1.2 of this appendix pertaining to the Hg monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also submit the monitoring plan information in § 75.53.(g) pertaining to the flow rate, diluent gas, and moisture monitoring systems within that same time frame, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information

update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.

7.2.4 *Certification, Recertification, and Quality-Assurance Test Reporting.* Except for daily QA tests of the required monitoring systems (*i.e.*, calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.10.1 through 7.1.10.7 of this section (except for test results previously submitted, *e.g.*, under the ARP) shall be submitted electronically, using the ECMPS Client Tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.5 *Quarterly Reports.*

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.9984, the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.90.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

7.2.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

Appendix B to Subpart UUUUU—HCl and HF Monitoring Provisions

1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

2. Monitoring of HCl and/or HF Emissions

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with Performance Specification 15 for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems in appendix B to part 60 of this chapter and § 63.10010(a).

2.2 *Primary and Backup Monitoring Systems.* The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The provisions of Performance Specification 15 Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 apply.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 The HCl and/or HF CEMS must be certified according to Performance Specification 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below. (**Please Note:** EPA plans to publish a technology neutral performance specification and appropriate on-going quality-assurance requirements for HCl CEMS in the near future along with amendments to this appendix to accommodate their use.)

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (i.e., independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A–8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348–03 (Reapproved 2010) "Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy" (incorporated by reference, see § 63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348–03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≥ R ≤ 130%; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} x\,100 \qquad \text{(Eq. B-1)}$$

3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

5.1 For on-going QA test requirements for HCl and HF CEMS, implement the quality assurance/quality control procedures of Performance Specification 15 of appendix B to part 60 of this chapter as set forth in sections 5.1.1 through 5.1.3 and 5.3.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within ± 5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, "quarterly" means once every "QA operating quarter" (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for "non-QA operating quarters" (*i.e.*, calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.3.3.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, "annual" means once every four "QA operating quarters" (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3 *Data Validation.*

5.3.1 *Out-of-Control Periods.* A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 *Grace Periods.* For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.4 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.*, 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.2 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 *General Requirements for HCl and HF CEMS.*

8.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair

activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 *Specific Requirements for HCl and HF CEMS.* The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with § 60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in appendix A–7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by 9.43×10^{-8} to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is 5.18×10^{-8}.

9.3.2 For electrical output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A–2 or A–3 in appendix A to this subpart (as applicable), replacing the value of K with 9.43×10^{-8} lb/scf-ppm (for HCl) or 5.18×10^{-8} (for HF) and defining C_h as the hourly average HCl or HF concentration in ppm. Then, use Equation A–4 in appendix A to this subpart to calculate the HCl or HF emission rate in lb/GWh. If the applicable HCl or HF limit is expressed in lb/MWh, divide the result from Equation A–4 by 10^3.

9.4 Use Equation A–5 in appendix A of this subpart to calculate the required 30 operating day rolling average HCl or HF emission rates. Round off each 30 operating day average to two significant figures. The term E_{ho} in Equation A–5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (*i.e,* flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.,* a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 *Contents of the Monitoring Plan.* For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under § 75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS Client Tool.

10.1.1.2.1 *Electronic.* Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (*i.e.,* CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 *Operating Parameter Records.* For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.3 *HCl and/or HF Emissions Records.* For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1 The date and hour;

10.1.3.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), rounded to three significant figures.

10.1.3.4 A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

10.1.4 *Stack Gas Volumetric Flow Rate Records.*

10.1.4.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (*i.e.,* lb/MWh or lb/GWh).

10.1.4.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

10.1.5 *Records of Stack Gas Moisture Content.*

10.1.5.1 Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1 To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2 To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A–7 to part 60 of this chapter.

10.1.5.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from § 75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

10.1.6 *Records of Diluent Gas (CO_2 or O_2) Concentration.*

10.1.6.1 To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO_2 or O_2 concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2 If hourly measurements of diluent gas concentration are needed, you must use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO_2 or O_2 concentration records, as specified in § 75.57(g) of this chapter.

10.1.7 *HCl and HF Emission Rate Records.* For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1 The date and hour;

10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, lb/MWh, or lb/GWh, as applicable, rounded to three significant figures), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For all required daily calibrations (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values, monitor responses, and calculated calibration error values;

10.1.8.1.2 For gas audits of HCl or HF CEMS, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each RATA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

10.1.8.2 *Additional Monitoring Systems.* For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59(a) of this chapter.

11. Reporting Requirements

11.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with § 63.10030.

11.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 Submit the electronic and hard copy information in section 10.1.1.2 of this appendix pertaining to the HCl and/or HF monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also, if applicable, submit monitoring plan information pertaining to any required flow rate, diluent gas, and/or moisture monitoring systems within that same time frame, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 *Certification, Recertification, and Quality-Assurance Test Reporting Requirements.* Except for daily QA tests (*i.e.*, calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

11.4.1 For daily calibrations (including calibration transfer standard tests), report the information in § 75.59(a)(1) of this chapter, excluding paragraphs (a)(1)(ix) through (a)(1)(xi).

11.4.2 For each quarterly gas audit of a HCl or HF CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (*e.g.*, quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (i.e., initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, as specified in Equation 2–4 of Performance Specification 2 in appendix B to part 60 of this chapter;

11.4.3.12 Confidence coefficient, as specified in Equation 2–5 of Performance Specification 2 in appendix B to part 60 of this chapter; and

11.4.3.13 Relative accuracy calculated using Equation 2–6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.9.3 of this appendix.

11.5 *Quarterly Reports.*

11.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.10005(g), (h), or (j) (whichever is earlier), the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack).

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[FR Doc. 2012–806 Filed 2–15–12; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2011–0344; FRL–9610–9]

RIN 2060–AQ68

National Emissions Standards for Hazardous Air Pollutants From Secondary Lead Smelting

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes the residual risk and technology review conducted for the secondary lead smelting source category regulated under national emission standards for hazardous air pollutants. These final amendments include revisions to the emissions limits for lead compounds; revisions to the standards for fugitive emissions; the addition of total hydrocarbon and dioxin and furan emissions limits for reverberatory and electric furnaces; the addition of a work practice standard for mercury emissions; the modification and addition of testing and monitoring, recordkeeping, and reporting requirements; related notifications; and revisions to the regulatory provisions related to emissions during periods of startup, shutdown, and malfunction.

DATES: This final action is effective on January 5, 2012. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of January 5, 2012.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2011–0344. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information (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 *http://www.regulations.gov*, or in hard copy at the EPA Docket Center, EPA West Building, Room Number 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket and Information Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Mr. Nathan Topham, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–0483; fax number: (919) 541–3207; and email address: *topham.nathan@epa.gov.* For additional contact information, see the following **SUPPLEMENTARY INFORMATION** section.

SUPPLEMENTARY INFORMATION: For specific information regarding the risk assessment and exposure modeling methodology, contact Dr. Michael Stewart, Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Toxics Assessment Group (C504–06), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–7524; fax number: (919) 541–0840; and email address: *stewart.michael@epa.gov.* For information about the applicability of this NESHAP to a particular entity, contact the appropriate person listed in Table 1 to this preamble.

TABLE 1—LIST OF EPA CONTACTS FOR THE NESHAP ADDRESSED IN THIS ACTION

NESHAP for	OECA contact [a]	OAQPS contact [b]
Secondary Lead Smelting	Maria Malave, (202) 564–7027, *malave.maria@epa.gov.*	Nathan Topham, (919) 541–0483, *topham.nathan@epa.gov.*

[a] EPA's Office of Enforcement and Compliance Assurance.
[b] EPA's Office of Air Quality Planning and Standards.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

CAA Clean Air Act
CBI confidential business information
CDX Central Data Exchange
CEMS continuous emission monitoring system
CPMS continuous parameter monitoring system
D/F dioxins and furans
ERT Electronic Reporting Tool
HAP hazardous air pollutants
HQ hazard quotient
ICR information collection request
lbs/yr pounds per year
MACT maximum achievable control technology
MIR maximum individual risk
NAAQS National Ambient Air Quality Standards
NESHAP National Emission Standards for Hazardous Air Pollutants
ng/dscm nanograms per dry standard cubic meter
NTTAA National Technology Transfer and Advancement Act
OP Office of Policy
ppbv parts per billion by volume
ppbw parts per billion by weight
ppmv parts per million by volume
ppmw parts per million by weight
REL recommended exposure limit
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RIN Regulatory Information Number
RTR Risk and Technology Review
SRF short rotary furnace
TEF toxic equivalency factor
TEQ toxic equivalency quotient
THC total hydrocarbons
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
UPL upper prediction limit
WWW World Wide Web

Background Information Document. On May 19, 2011 (76 FR 29032), the EPA proposed revisions to the Secondary Lead Smelting NESHAP based on evaluations performed by the EPA in order to conduct our risk and technology review. In this action, we are finalizing decisions and revisions for the rule. Some of the significant comments and our responses are summarized in this preamble. A summary of the public comments on the proposal not presented in the preamble, and the EPA's responses to those comments, is available in Docket ID No. EPA–HQ–OAR–2011–0344. A tracked changes version of the regulatory language that incorporates the changes in this action is available in the docket.

Organization of This Document. The following outline is provided to aid in locating information in the preamble.

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I. General Information

A. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action are shown in Table 2 of this preamble.

TABLE 2—NESHAP AND INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

NESHAP and source category	NAICS [a] Code	MACT [b] Code
Secondary Lead Smelting	331492	0205

[a] North American Industry Classification System.
[b] Maximum Achievable Control Technology.

Table 2 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by the final action for the source category listed. To determine whether your facility would be affected, you should examine the applicability criteria in the appropriate NESHAP. As defined in the source category listing report published by the EPA in 1992, the Secondary Lead Smelting source category is defined as any facility at which lead-bearing scrap materials (including, but not limited to lead acid batteries) are recycled by smelting into elemental lead or lead alloys.[1] For clarification purposes, all reference to lead emissions in this preamble means "lead compounds" (which is a hazardous air pollutant) and all reference to lead production means elemental lead (which is not a hazardous air pollutant) as provided under CAA section 112(b)(7).

If you have any questions regarding the applicability of any aspect of this NESHAP, please contact the appropriate person listed in Table 1 of this preamble in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. What is the affected source?

The final rule applies to owners and operators of secondary lead smelters. The affected source for this subpart is any of the following sources at a secondary lead smelter: Blast, reverberatory, rotary, and electric furnaces; refining kettles; agglomerating furnaces; dryers; process fugitive emissions sources; buildings containing lead bearing materials; and fugitive dust sources. A new affected source is any affected source at a secondary lead smelting facility of which the construction or reconstruction commenced after May 19, 2011. If components of an existing affected source are replaced such that the replacement meets the definition of reconstruction in 40 CFR 63.2 and the reconstruction commenced on or after May 19, 2011, then the existing source becomes a reconstructed source and is subject to the relevant standards for a new affected source. The reconstructed source must comply with the requirements for a new affected source upon initial startup of the reconstructed source, or by March 5, 2012, whichever is later.

[1] USEPA. Documentation for Developing the Initial Source Category List—Final Report, USEPA/OAQPS, EPA–450/3–91–030, July, 1992.

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

In addition to being available in the docket, an electronic copy of this final action will also be available on the World Wide Web through the Technology Transfer Network (TTN). Following signature, a copy of the final action will be posted on the TTN's policy and guidance page for newly proposed and promulgated rules at the following address: *http://www.epa.gov/ttn/caaa/new.html.* The TTN provides information and technology exchange in various areas of air pollution control.

Additional information is available on the residual risk and technology review (RTR) web page at *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html.* This information includes source category descriptions and detailed emissions and other data that were used as inputs to the risk assessments.

D. Judicial Review

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by March 5, 2012. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania

Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background

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

For MACT standards, the statute specifies certain minimum stringency requirements, which are referred to as floor requirements and may not be based on cost considerations. See CAA section 112(d)(3). For new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best controlled similar source. The MACT standards for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT, we must also consider control options that are more stringent than the floor, under CAA section 112(d)(2). We may establish standards more stringent than the floor, based on the consideration of the cost of achieving the emissions reductions, any non-air quality health and environmental impacts, and energy requirements. In promulgating MACT standards, CAA section 112(d)(2) directs us to consider the application of measures, processes, methods, systems, or techniques that reduce the volume of or eliminate HAP emissions through process changes, substitution of materials, or other modifications; enclose systems or processes to eliminate emissions; collect, capture, or treat HAP when released from a process, stack, storage, or fugitive emissions point; and/or are design, equipment, work practice, or operational standards.

In the second stage of the regulatory process, we undertake two different analyses, as required by the CAA: section 112(d)(6) of the CAA calls for us to review these technology-based standards and to revise them "as necessary (taking into account developments in practices, processes, and control technologies)" no less frequently than every 8 years; and within 8 years after promulgation of the technology standards, CAA section 112(f) calls for us to evaluate the risk to public health remaining after application of the technology-based standards and to revise the standards, if necessary, to provide an ample margin of safety to protect public health or to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. In doing so, the EPA may adopt standards equal to existing MACT standards if the EPA determines that the existing standards are sufficiently protective. *NRDC* v. *EPA*, 529 F.3d 1077, 1083 (DC Cir. 2008).

On May 19, 2011, the EPA published a proposed rule in the **Federal Register** for the Secondary Lead Smelting NESHAP, 40 CFR part 63, subpart X that took into consideration the residual risk and technology review (RTR) analyses. Today's action provides the EPA's final determinations pursuant to the RTR provisions of CAA section 112 for the Secondary Lead Smelting source category, and also promulgates first-time standards under section 112 (d)(2) (MACT) for certain hazardous air pollutants emitted by secondary lead smelters. Specifically, we are taking the following actions:

- Revising some requirements of the NESHAP related to control of metal HAP emissions based on our risk assessment and technology reviews.
- Finalizing first-time total hydrocarbon (THC) and dioxin and furan (D/F) emissions limits and a plastic separation work practice standard to prevent dioxin formation.
- Finalizing work practice standards for mercury.
- Revising the requirements in the NESHAP related to emissions during periods of startup, shutdown, and malfunction (SSM).
- Incorporating the use of plain language into the rule.
- Addressing technical and editorial corrections in the rule.

III. Summary of the Final Rule

A. What are the final rule amendments for the Secondary Lead Smelting source category?

EPA promulgated the National Emission Standards for Hazardous Air Pollutant Emissions: Secondary Lead Smelting on June 13, 1997 (62 FR 32216). The standards are codified at 40 CFR part 63, subpart X. The secondary lead smelting industry consists of facilities that recycle lead-bearing scrap material, typically lead acid batteries, into elemental lead or lead alloys. The source category covered by this MACT standard currently includes 16 facilities, including one facility that is not currently operating and one facility that is in the process of being constructed.

This section describes the final amendments to the secondary lead smelting NESHAP.[2] These revisions include changes to the stack and fugitive metal HAP emission standards, the addition of new THC and D/F emission limits, the addition of a work practice standard to separate plastics from automotive batteries to prevent dioxin emissions, the addition of work practice standards to minimize mercury emissions, and changes to the requirements that apply during periods of startup, shutdown, and malfunction. In addition to these changes described below, we are making minor changes to the regulatory text to correct editorial errors and to make plain language revisions. We have evaluated the cost, emissions reductions, energy implications and cost effectiveness of all of the standards being promulgated in this final rule and have determined that these measures are cost effective, technically feasible and will provide the public with an ample margin of safety from exposure to emissions from the secondary lead smelter source category. See *Cost Impacts of the Revised NESHAP for the Secondary Lead Smelting Source Category*, which is available in the docket, for information on the costs and cost effectiveness of each of the standards being promulgated in this final rule.

1. Stack and Fugitive Metal HAP Emission Standards

For the reasons provided in Section IV.A of this preamble and in the support documents in the docket, we have determined that the risks associated with emissions from this source

[2] Note that the EPA is reprinting portions of the language from the 1997 NESHAP here so the entire rule appears in one place, for readers' convenience. The EPA is not amending, reopening or otherwise reconsidering these reprinted portions of the 1997 rule.

category are unacceptable primarily due to fugitive emissions of lead. We have further determined that there have been developments in practices, processes, and control technologies that warrant revisions to the MACT standard (*i.e.*, the standards promulgated pursuant to section 112(d)(2) and (3)) for this source category. Therefore, to satisfy the requirements of CAA sections 112(d)(6) and 112(f), we are revising the MACT standard to include:

• A facility wide, flow weighted average lead [3] emissions limit from stacks of 0.20 mg/dscm and an individual stack lead emissions limit of 1.0 mg/dscm for each stack at existing sources. For new sources, a lead emissions limit of 0.20 mg/dscm applies to each individual stack at a modified or "greenfield" new facility.

• A requirement for the facility to operate sources of fugitive lead emissions within total enclosures that are maintained under negative pressure and vented to a control device. These sources of fugitive emissions include the smelting furnaces, smelting furnace charging areas, lead taps, slag taps, molds during tapping, battery breakers, refining kettles, casting areas, dryers, material handling areas, and areas where dust from fabric filters, sweepings or used fabric filters are processed. The facilities are also required to adopt a list of specified work practice standards to minimize fugitive emissions.

2. Organic HAP Emissions Standards

To satisfy CAA sections 112(d)(2) and 112(d)(3), we are also revising the MACT standard to include first-time D/F and THC emission limits (with THC serving as a surrogate for non-dioxin organic HAP). These emission limits are summarized in Table 3 of this preamble.

TABLE 3—SUMMARY OF NEW THC AND D/F EMISSION LIMITS

Source type	D/F Emission limit [a]	THC Emission Limit [b]
New and Existing Collocated Blast and Reverberatory Furnaces	0.50	[c] 20
Existing Blast Furnaces	170	[c] 360
New Blast Furnaces	10	[c] 70
New and Existing Reverberatory and Electric Furnaces	1.0	12

[a] ng/dscm on a TEQ basis, corrected to 7 percent O_2.
[b] ppmv as propane, corrected to 4 percent CO_2.
[c] Emission limit is unchanged from 1997 NESHAP.

3. Startup, Shutdown, and Malfunction

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

We have eliminated the SSM exemption for secondary lead smelting facilities in this rule. Consistent with *Sierra Club* v. *EPA*, the EPA has established standards in this rule for all periods of operation. We have also revised Table 1 to subpart X (the General Provisions table) in several respects. For example, we have eliminated that incorporation of the General Provisions' requirement that the source develop an SSM plan. We have also eliminated or revised certain recordkeeping and reporting that related to the SSM exemption. The EPA has attempted to ensure that we have not included in the regulatory language any provisions that are inappropriate, unnecessary, or redundant in the absence of the SSM exemption.

In establishing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained below, has established different standards for non-dioxin organic HAP during those periods.

Information on periods of startup and shutdown in the industry indicate that lead emissions during these periods do not increase (consistent with our engineering judgment that lead emissions would not increase during these periods because lead-bearing feed is not being smelted during these periods). Furthermore, all lead-emitting processes are controlled by either control devices or work practices and these controls would not typically be affected by startup or shutdown. Therefore, the EPA is not adopting separate lead-emission standards for periods of startup and shutdown.[4]

The EPA has revised this final rule to require sources to meet a work practice standard that requires the development of standard operating procedures designed to minimize emissions of THC for each start-up and shutdown scenario anticipated for all units subject to THC limits. Temperature monitoring is the metric used to determine continuous compliance with emission standards for THC. This metric is inappropriate as a measure of the destruction efficiency of these organic pollutants during periods of startup and shutdown.

The EPA is not including a standard for dioxins and furans during periods of startup and shutdown. This is because dioxins and furans will not be emitted during those periods. During startup and shutdown, scrap feed materials (including chlorinated plastics and flame retardants) that contain the precursors needed for dioxin formation are not introduced into the smelter [5] so there are no conditions that could give rise to dioxin and furan emissions.

The EPA determined that it is not technically and economically feasible for units subject to THC limits to perform stack testing for this pollutant during periods of startup and shutdown due to technical and economic

[3] Throughout this preamble, all references to lead emissions means lead compounds as listed by Congress at section 112(b)(1) of the Act.

[4] Since startup and shutdown refers to the smelting process, and not to ancillary management activities, there are no startup and shutdown standards for process fugitive emissions since startup and shutdown do not occur for the activities generating such emissions.

[5] "Shutdown" is defined as a period "when no lead bearing materials are being fed to the furnace and smelting operations have ceased * * *". Section 63.542 (definition of "shutdown").

impracticality associated with testing secondary lead smelting furnaces during these periods. The furnaces are heated during periods of startup through slow feeding of natural gas and small amounts of coke, with no lead acid batteries fed to the furnace during these periods. Test crews would have to be on-site prior to a period of startup or shutdown occurring and may need to break up a single test over multiple startups or shutdowns, the length of which could vary depending on the type of secondary lead smelting furnace being tested, that would happen infrequently to gather enough data to complete a three-run test. See also section V.G of this preamble discussing these standards further.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 63.2). The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. Under section 112, emissions standards for new sources must be no less stringent than the level "achieved" by the best controlled similar source and for existing sources generally must be no less stringent than the average emission limitation "achieved" by the best performing 12 percent of sources in the category. There is nothing in section 112 that directs the agency to consider malfunctions in determining the level "achieved" by the best performing or best controlled sources when setting emission standards. Moreover, while the EPA accounts for variability in setting emissions standards consistent with the section 112 case law, nothing in that case law requires the agency to consider malfunctions as part of that analysis. Section 112 uses the concept of "best controlled" and "best performing" unit in defining the level of stringency that section 112 performance standards must meet. Applying the concept of "best controlled" or "best performing" to a unit that is malfunctioning presents significant difficulties, as malfunctions are sudden and unexpected events.

Further, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not "reasonably" foreseeable. See, *e.g., Sierra Club* v. *EPA*, 167 F. 3d 658, 662 (DC Cir. 1999) (EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem.) We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to "invest the resources to conduct the perfect study". See also, *Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (DC Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties', such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation."). In addition, the goal of a best-controlled or best-performing source is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with CAA section 112 and is a reasonable interpretation of the statute. In section 3.2.1 of the separate response to comment document, we respond to comments that emissions during malfunctions should be accounted for in assessing risk pursuant to CAA section 112(f)(2).

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (September 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions* (February 15, 1983).) The EPA is therefore adding to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. See 40 CFR 63.542 (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also have added other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 63.552 (see 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *." The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.552 and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *." In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 (see also 40 CFR 22.27).

The EPA is including an affirmative defense in the final rule in an attempt to balance a tension, inherent in many types of air regulations, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that "limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis" 42 U.S.C. 7602(k) (defining "emission limitation and emission standard"). See generally *Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (DC Cir. 2008). Thus, the EPA is required to ensure that section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief. While "continuous" limitations, on the one hand, are required, there is also case law indicating that in many situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (DC Cir. 1973), the DC Circuit acknowledged that in setting standards under CAA section 111 "variant provisions" such as provisions allowing for upsets during startup, shutdown and equipment malfunction "appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force." See also, *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (DC Cir. 1973). Though intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments undermine the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating "upsets beyond the control of the permit holder." *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). But see *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (DC Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission limitations are "continuous" as required by 42 U.S.C. 7602(k) and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

B. What are the effective and compliance dates of the standards?

The revisions to the MACT standards being promulgated in this action are effective on January 5, 2012. For the MACT standards being addressed in this action, the compliance date for the revised SSM requirements is the effective date of the standards, January 5, 2012. The compliance date for existing sources for the revised stack lead emission limit and the revised fugitive emission standard including the requirement to adopt work practice standards and install total enclosures for specified process fugitive emission sources, and for the new D/F and THC emission limits, is 2 years from the effective date of the standard, January 6, 2014. New sources must comply with the all of the standards immediately upon the effective date of the standard, January 5, 2012, or upon startup, whichever is later.

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

In this action, as a step to increase the ease and efficiency of data submittal and improve data accessibility, the EPA is requiring the electronic submittal of select performance test data. Specifically, the EPA is requiring owners and operators of secondary lead smelting facilities to submit electronic copies of performance test reports required under 40 CFR 63.543 to the EPA's WebFIRE database. The WebFIRE database was constructed to store performance test data for use in developing emission factors. A description of the WebFIRE database is available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.*

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

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

State, local, and tribal agencies can also benefit from a more streamlined and accurate review of electronic data submitted to them. The ERT allows for an electronic review process rather than a manual data assessment making review and evaluation of the data and calculations easier and more efficient.

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

The requirement to submit performance test data electronically to the EPA does not create any additional performance testing and would apply only to those performance tests conducted using test methods that are supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at *http://*

www.epa.gov/ttn/chief/ert/index.html. We believe that industry will benefit from this new electronic data submittal requirement. Having these data, the EPA will be able to develop improved emission factors, make fewer information requests, and promulgate better regulations. The information to be reported is already required for the existing test methods and is necessary to evaluate the conformance to the test method.

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

IV. Summary of Significant Changes Since Proposal

A. Changes to the Risk Assessment Performed Under CAA Section 112(f)

In the proposed rulemaking, the EPA presented a number of options for additional controls on the Secondary Lead Smelting source category. In that notice, the EPA solicited comment on the proposed options as well as on all of the analyses and data upon which the options were based, including the risk methods and results presented in the draft document: *Residual Risk Assessment for the Secondary Lead Smelting Source Category.*

During the public comment period for the proposed rule, several parties submitted comments and suggested revisions regarding the emissions used for the risk assessment, and also submitted other information relevant to the risk assessment (see docket ID EPA–HQ–OAR–2011–0344 for all public comments). After considering these submissions, the EPA revised its analyses. Revised methods, model inputs, and risk results are presented in the report: *Residual Risk Assessment for the Secondary Lead Smelting Source Category,* which is available in the docket for this rulemaking. In addition, a discussion of the updated emissions information used in the final risk assessment can be found in the memorandum titled: *Development of the RTR Emissions Dataset for the Secondary Lead Smelting Source Category,* which can also be found in the docket for this rulemaking.

Considering the updated emissions information received during the public comment period for the proposed rule, our final risk analysis estimates that the primary NAAQS for lead, used in this rule as a measure of acceptable risk from air-borne lead emissions, could be exceeded at 9 of 15 facilities based on actual emissions, largely due to fugitive dust emissions (see Table 4). At these 9 facilities, fugitive dust emissions account for about 94 to 99 percent of the estimated 3-month maximum lead concentrations.[6] Our analysis also estimates that approximately 200 people live in areas around three of these facilities where 3-month maximum lead concentrations are estimated to be between one and three times above the lead NAAQS. Allowable stack emissions of lead also resulted in modeled concentrations exceeding the NAAQS, with modeled lead ambient air levels as high as 8 and 10 times above the NAAQS. This analysis also estimates that 3-month maximum lead concentrations from a secondary lead smelter could be up to about 20 times the NAAQS for lead based on actual emissions. The maximum lead exceedances at populated census block centroids were between one and three times the NAAQS. There is some uncertainty associated with the fugitive emissions estimates that is derived from the uncertainty involved in determining the housekeeping and enclosure factors. This uncertainty could have important impacts on the estimated fugitive emissions and the resulting modeled ambient concentration. For example, if the level of control assumed through the use of full enclosure and robust housekeeping were both increased from 75 percent to 85 percent, the estimated fugitive emissions at the RSR facility would be about 43 pounds (roughly three times lower than those estimated in this rule). If the level of control assumed through the use of full enclosure and robust housekeeping were both decreased from 75 percent to 65 percent, the estimated fugitive emissions at the RSR facility would be about 240 pounds (roughly two times higher than those estimated in this rule). As shown in this example, changing the estimates of control efficiency achieved with full enclosure and robust housekeeping practices by 10 percent each could impact the resulting fugitive emission estimates for facilities employing that level of control by two to three times. These estimates could significantly impact the resulting risk estimates since most of the impact of lead emissions was due to fugitive dust emissions. While there are uncertainties associated with estimating fugitive emissions, we conclude that the methodology used in this rulemaking provided reasonable estimates of fugitive emissions for these sources. For further details, see *Development of the RTR Emissions Dataset for the Secondary Lead Smelting Source Category,* available in docket ID EPA–HQ–OAR–2011–0344, which describes how we developed these fugitive emissions estimates and provides a presentation of our estimates compared to estimates submitted via the ICR and estimates reported to the TRI.

[6] For all facilities, the percent contribution of fugitive and stack emissions to modeled ambient lead concentrations has only been estimated for the model receptor representing the site of maximum lead impact.

TABLE 4—SECONDARY LEAD SMELTING FACILITY MODELED MAXIMUM AMBIENT LEAD CONCENTRATIONS CONSIDERING ACTUAL EMISSIONS [a]

[Rolling 3-month average values]

Facility name	City	State	Highest modeled lead concentration ($\mu g/m^3$)	Concentration is X times the NAAQS
Doe Run Company-Buick Mill	Boss	MO	2.36	20
Sanders Lead Co	Troy	AL	2.16	10
Exide Corporation	Vernon	CA	1.14	8
Battery Recycling Co	Arecibo	PR	0.76	5
Gulf Coast Recycling, Inc	Tampa	FL	0.38	3
Exide Technologies–Canon Hollow Plant	Forest City	MO	0.47	3
Gopher Resource Corp	Eagan	MN	0.35	2
Frisco Battery Recycling	Frisco	TX	0.23	2
Exide Tech/Reading Smelter	Reading	PA	0.25	2
Quemetco, Inc	Industry	CA	0.17	1
Exide Technologies	Muncie	IN	0.15	1
Exide Technologies/B R Smelter	Baton Rouge	LA	0.14	1
Revere Smelting & Refining Corp	Middletown	NY	0.10	0.7
Quemetco, Inc	Indianapolis	IN	0.07	0.5
East Penn Mfg. Co Inc/Smelter Plt	Lyon Station	PA	0.02	0.1

[a] Values of 1 or less in the last column indicate that modeled lead concentrations are at or below the NAAQS for lead.

We also note that there were changes to our cancer, acute, and PB–HAP multipathway case study analyses (see section 3.4 of the risk assessment document) for non-lead HAP as a result of the updated risk assessment performed for the final rule. With respect to our updated cancer risk assessment, we estimate that the maximum individual risk (MIR) of cancer due to actual emissions is 50 in a million predominantly due to fugitive dust emissions of arsenic and cadmium as compared to the analysis at proposal of risk of 50 in a million but based on a different secondary lead facility. Moreover, approximately 700 people were estimated to have cancer risks above 10 in a million and approximately 80,000 people were estimated to have cancer risks above 1 in a million considering all facilities in this source category (as compared to the analysis at proposal of 1,500 above 10 in a million and 128,000 above 1 in a million). In addition, the MIR due to MACT allowable emissions remains 200 in a million predominantly from stack emissions of arsenic. The updated worst-case acute hazard quotient (HQ) value is 20 at two facilities (based on the REL for arsenic; the REL is the only available acute health benchmark value for arsenic and all other pollutants had HQ values less than or equal to 1), driven by both stack and fugitive dust emissions of arsenic (as compared to analysis at proposal of an acute HQ value of 30 based on the REL for arsenic at one facility driven by emissions from stacks). Finally, the risk assessment supporting the final rulemaking estimates that the cancer MIR values from both multipathway case study analyses (*i.e.*, in Frisco, TX and Middletown, NY; see section 3.2 of the final risk assessment document) are less than 1 in a million (as compared to an estimated multipathway MIR of 30 in a million and less than 1 in a million in the Frisco, TX and Middletown, NY multipathway case study analyses for the proposed rule). Notably, the reduction in multipathway risks resulted from updated emissions information received during the public comment period with respect to these facilities.

Taking into account all the results of the final risk assessment, and similar to the proposed rulemaking, we conclude that risks to public health due to emissions from this source category are unacceptable. Our conclusion is primarily based on risk from exposure to air-borne lead emissions but also considers other risk metrics such as cancer and non-cancer risks associated with actual and allowable stack emissions of non-lead HAPs, especially arsenic and cadmium. As mentioned above, actual lead emissions resulted in modeled concentrations of lead above the lead NAAQS at 9 of 15 facilities. Thus, we note that allowable stack emissions of lead and other HAP metals and fugitive emissions of lead must be reduced to assure that lead concentrations in ambient air beyond the facility fenceline are acceptable—that is, do not exceed the lead NAAQS (the measure of risk acceptability for exposure to air-borne lead in this rule). The fact that maximum individual cancer risks due to actual emissions are above 1 in a million also contributes to our determination of unacceptability, but to a lesser extent. While the estimated maximum individual cancer risks due to actual emissions would, by themselves, not generally lead us to a determination that risks are unacceptable, the fact that they occur along with the exceedences of the lead primary NAAQS adds to our concern about these exposures, and further supports our proposed determination that risks are unacceptable. To provide acceptable levels of risk with an ample margin of safety, we are finalizing the requirement that secondary lead smelting facilities must operate the following fugitive dust emissions sources within total enclosures that must be maintained at negative pressure at all times and vented to a control device designed to capture lead particulate: Smelting furnaces, smelting furnace charging areas, lead taps, slag taps, molds during tapping, battery breakers, refining kettles, casting areas, dryers, material handling areas managing lead bearing materials, and areas where dust from fabric filters, sweepings, or used fabric filters are processed. As further described in Section IV.C of this preamble, based on public comments, we are not adopting the proposed alternative to demonstrate compliance by monitoring lead at or near the property boundary based on a 3-month rolling average in lieu of constructing total enclosures. (See 76 FR 29056.) We are finalizing the proposed requirement for facilities to conduct fugitive emission work practices as well

as to enclose fugitive emission sources. As further described in Section IV.C of this preamble, we are also promulgating a revised list of required work practices based on a number of comments received regarding the necessity, efficacy, and safety of the work practices which the EPA proposed.

We are also finalizing the proposed requirement limiting stack lead emissions to 0.2 mg/dscm as a facility-wide emissions average and limiting stack lead emissions from any single stack to 1.0 mg/dscm.

After implementation of the controls required in this final rule, we estimate that there will be no one living at a census block centroid exposed to ambient concentrations above the NAAQS due to these facilities and the cancer MIR due to actual emissions will decrease from 50 in a million to 7 in a million.

B. Changes to the Technology Review Performed Under CAA Section 112(d)(6)

Based on the technology review under CAA section 112(d)(6), the EPA proposed to change the stack lead emission limits from 2.0 mg/dscm for any individual stack to a facility-wide, flow-weighted average emission limit of 0.20 mg/dscm with a limit of 1.0 mg/dscm applicable to any individual stack. The proposed limit was based on emissions data collected from industry, which indicated that well-performing baghouses currently used by much of the industry are capable of achieving outlet lead concentrations significantly lower than the limit of 2.0 mg/dscm adopted in the 1997 MACT standard. We have considered the public comments on this issue and are adopting the limits as proposed.

Under CAA section 112(d)(6), we also proposed a fugitive emission standard requiring operation of the following process fugitive emission sources in total enclosures that are maintained under negative pressure at all times and vented to a control device: Smelting furnaces, smelting furnace charging areas, lead taps, slag taps, and molds during charging, battery breakers, refining kettles, casting areas, dryers, agglomerating furnaces and agglomerating furnace product taps, material handling areas for any lead bearing materials, and areas where dust from fabric filters, sweepings, or used fabric filters are processed. This proposed requirement was based on information collected from the industry that indicated that several operating facilities currently enclose most or all of their process fugitive emission sources, and that the ambient lead concentrations near these facilities are significantly lower than those facilities that do not have enclosures. We have considered the public comments on this issue, and have decided to adopt the requirements largely as proposed. This requirement is identical to that adopted to eliminate unacceptable risk for fugitive emissions pursuant to CAA section 112 (f)(2). However, as described in Section IV.C of this preamble, based on public comments, we are not adopting the proposed alternative to demonstrate compliance by monitoring lead at or near their property boundary based on a 3-month rolling average in lieu of constructing total enclosures. (See 76 FR 29056.) We are finalizing the proposed requirement for facilities to conduct fugitive emission work practices as well as to enclose fugitive emission sources. As further described in Section IV.C of this preamble, we are also promulgating a revised list of required work practices based on a number of comments received regarding the necessity, efficacy, and safety of the work practices which the EPA proposed.

We are also finalizing the requirement limiting stack lead emissions to 0.2 mg/dscm as a facility-wide emissions average and limiting stack lead emissions from any single stack to 1.0 mg/dscm as proposed.

We note that although we have adopted the same standards under both CAA sections 112(f)(2) and 112(d)(6), these standards rest on independent statutory authorities and independent rationales. Consequently, these standards remain independent and legally severable.

C. Other Changes Since Proposal

We received over 30 public comments on the proposed rule. After considering these comments, we are making the following additional changes to the proposal. The rationale for these and any other significant changes can be found in this preamble and in the comment response document available in the docket.

1. Stack Emission Limits

- The EPA is not adopting numerical limits for THC and D/F emissions from rotary furnaces pending further data-gathering and analysis for this furnace type.
- For units constructed after June 9, 1994, the EPA is adding a limit for THC and D/F for collocated blast and reverberatory furnaces when the reverberatory furnace is not operating, and is amending the D/F limits for blast furnaces for units that commenced construction after June 9, 1994. We also added a THC and D/F new source limit for blast furnaces that commence construction or reconstruction after May 19, 2011.

2. Definitions

- Definitions have been added for "affected source" and "new source" to clarify when the standards for new sources would apply.
- A definition of "lead-bearing material" has been added to the rule to clarify requirements for material handling area enclosures and work practices for fugitive emissions.
- The definition of "material storage and handling" has been revised to exclude transfer of raw materials in enclosed containers.
- The definition of "plant roadway" has been revised to exclude roadways inside total enclosures.
- The definition of "process vent" has been revised to specify that it includes only vents from lead processing equipment and from buildings containing lead bearing material.
- Definitions for "leeward," "windward," and "natural draft opening" have been added to the rule to clarify the differential pressure and monitoring requirements and the requirement to maintain an inward flow of air through enclosure openings.
- The definition of "total enclosure" was modified by specifically including modified text from 40 CFR 265.1101 and EPA method 204 "Criteria for and Verification of a Permanent or Temporary Total Enclosure" rather than citing the reference to the requirements for a hazardous waste containment area. We also clarified the requirement for total enclosures to be vented to a control device designed to capture lead particulates.

3. Enclosure Requirements

- The proposed requirement to maintain an in-draft velocity of 300 feet per minute at enclosure openings (see 76 FR 29072) was replaced with a requirement to maintain an inward flow of air through all natural draft openings.
- The proposed requirement for a back-up power source for the differential pressure monitors required for the total enclosures (see 76 FR 29077) was eliminated, and a reporting requirement was added to identify periods when the power was lost to the monitoring system.
- The proposed rule (see 76 FR 29072) has been modified to clarify that activities required for inspection of fabric filters and maintenance of filters that are in need of removal and replacement are not required to be conducted inside of total enclosures.

• Lead ingot product handling, storm water and wastewater treatment, intact battery storage areas, and clean battery casing plastic handling activities are not subject to the total enclosure requirement.

4. Fugitive Emission Work Practice Requirements

• The proposed maintenance requirements (see 76 FR 29073) have been modified to allow emergency repairs of ductwork or structure leaks to occur outside of enclosures if the time to construct a temporary enclosure would exceed the time to make a temporary or permanent repair. The proposed rule has been modified to extend the deadline for required maintenance and repair on total enclosures to one week after identification of any gaps, breaks, separations, leak points or other possible routes for emissions of lead to the atmosphere. The final rule also clarifies that once an item that is not otherwise subject to total enclosure requirements has been cleaned, its maintenance is no longer subject to the enclosure requirement.

• The proposed rule has been edited to allow for existing control devices to treat the ventilation from temporary enclosures constructed for maintenance purposes if the device and its permit account for increased airflow and emissions for this activity.

• The roof washing proposed work practice (see 76 FR 29073) has been removed from the list of required fugitive emission work practices.

• The specific proposed water application rate of 0.48 gallons per square yard (see 76 FR 29073) has been removed from the road washing requirement.

• The proposed battery storage area inspection frequency (see 76 FR 29073) has been changed from twice per day to once per week to maintain consistency with inspection frequency required under other regulatory programs.

• The proposed requirement to collect wash water in a container that is not open to the atmosphere (see 76 FR 29073) has been removed.

• The proposed rule (see 76 FR 29073) has been revised to clarify that lead-bearing dust must be collected and transported within closed conveyor systems or in sealed, lead-proof containers while other lead bearing material must be contained and covered in a manner that prevents spillage or dust formation.

• The proposed requirement for cleaning after an accidental release (see 76 FR 29073) has been clarified to include only those releases that exceed the CERCLA reportable quantity for lead (*e.g.*, 10 pounds).

5. Testing and Monitoring Requirements

• The performance testing requirements (see 76 FR 29074) have been modified to allow facilities to use EPA Method 12 or Method 29 for lead compounds.

• A provision was added allowing for biannual testing of lead compounds and THC for sources that demonstrate concentrations that are less than 50 percent of the applicable limit.

• An exemption was provided for THC testing if a facility has installed and is using a THC CEMS.

• The time between D/F testing (see 76 FR 29072) was changed from once every 5 years to once every 6 years, in anticipation that most facilities would be on a biannual testing schedule for lead and THC, and this schedule would allow coordination of the two required tests.

• The conditions for the performance tests (see 76 FR 29072) were changed from "under such conditions as the Administrator specifies * * *" to "maximum representative operating conditions for the process".

• The EPA also added a provision stating that sources which operate a HEPA filter or WESP system downstream of a primary particulate (lead) control device are not subject to a bag leak detection system (BLDS) requirement.

6. Other Changes

• A provision was added for sources to develop procedures to minimize emissions of THC limits during periods of startup and shutdown.

• We modified the proposed plastic separation work practice requirement (see 76 FR 29072) to include only plastic battery casing materials from automotive batteries (which comprise the vast majority of input plastics).

• The proposed recordkeeping and reporting requirements were revised to be consistent with the other changes made to the rule.

A tracked changes version of the regulatory language incorporating the changes in this action is available in the docket. Additionally, a summary of the public comments that are not in the preamble can be found in the comment response document available in the docket.

V. Summary of Significant Comments and Responses

A. Use of Lead Primary NAAQS as a Measure of Acceptability of Risk for Public Health

Commenters from both the environmental and industry sectors challenged the EPA's use of the lead primary NAAQS as a measure of acceptability of risk in this rule. The EPA disagrees with these comments. The EPA has reasonably applied the lead primary NAAQS as a measure of evaluating acceptability or unacceptability of risk from exposure to lead emissions from sources in this category. The lead primary NAAQS targets protection to children living near sources, such as secondary lead smelters, who are exposed at the level of the standard—the population most sensitive to the health impacts of these emissions. Moreover, using the lead primary NAAQS to assess acceptability of risk does not amount to an impermissible implementation of the lead primary NAAQS as industry commenters would have it. Full responses to these comments are found in the Response to Comment Document for this rulemaking, available in docket ID EPA–HQ–OAR–2011–0344.

B. Total Enclosure Requirements

Comment: Several commenters supported a requirement for total enclosures of enumerated sources of fugitive emissions. Some of those commenters did not support the alternative that would have allowed ambient monitoring in lieu of total enclosures.

According to one commenter, "The purpose of establishing emission standards and control technology regulations is to reduce, by empirically proven technical means, the release of hazardous air pollutants into the atmosphere." The commenter therefore recommended that the EPA require enclosures in all instances to limit fugitive emissions.

According to another commenter, "The non-cancer and cancer risk reductions associated with total enclosures of all lead bearing processes to reduce fugitive emissions are clearly demonstrated for all facilities in the post control scenario contained in the residual risk assessment. These benefits also have been observed based on our experience with total enclosures that are under negative pressure and vented to air pollution controls. * * * The annual geometric mean of lead measured [in ambient air near the facility] dropped from a high of 0.71 $\mu g/m^3$ (1987) to 0.06 $\mu g/m^3$ (1993) after all of the point source

and fugitive emission controls were in place. The benefits of requiring total enclosures as demonstrated by the ambient monitoring results were clearly apparent to the Department and surrounding community. Based on that experience, we do not support the alternative of allowing partial enclosures with an air monitoring requirement option in this rulemaking."

Another commenter stated "We do not support allowing partial enclosures with an air monitoring requirement option, since the total enclosures have been shown to be extremely effective in reducing fugitive emissions of lead and the other metal HAPs from these sources."

One commenter indicated that neither proposed alternative (total enclosure or the ambient monitoring alternative) complies with CAA section 112(d)(6) but did state that "additional health risk reductions would occur if a facility used total enclosure." This commenter also stated that the EPA should require total enclosures and work practice standards beyond those included in the proposed rule to control fugitive dust emissions of arsenic and cadmium and achieve reductions in cancer and non-cancer risks from these pollutants.

Alternatively, one commenter disagreed that total enclosure is the most effective method to reduce emissions. According to the commenter, "Capturing emissions from secondary lead smelting sources at the point of emission and controlling such emissions through the use of baghouses equipped with secondary HEPA filtration systems represents a better alternative to constructing and maintaining total enclosures around secondary lead smelting sources."

Response: As explained at 76 FR 29059 in the proposed rule and below, the EPA is amending the NESHAP for fugitive emissions of lead both because these emissions pose an unacceptable risk under CAA section 112(f) and because it is technically appropriate and necessary to do so pursuant to section 112(d)(6). With respect to what changes to adopt, we agree with those commenters who argued that total enclosures maintained under negative pressure are the most effective means by which to reduce fugitive emissions. Facilities in this source category that implement total enclosures as a means of controlling fugitive emissions are able to achieve significantly lower ambient lead concentrations near the boundaries of their facilities, as clearly demonstrated in the *Summary of Ambient Lead Monitoring Data Around Secondary Lead Smelting Facilities* document available in docket ID EPA–HQ–OAR–2011–0344. About half of the existing facilities currently have such full enclosures, and a few other facilities are currently constructing such enclosures. The prevalence of total enclosures in the secondary lead smelting source category suggests that this measure is cost effective and it is clearly technically feasible. There is more certainty that fugitive emissions are well controlled through the use of total enclosures than would exist with the proposed alternative to use fenceline ambient monitoring. The work practice standards in the final rule have been revised from those proposed to ensure that there are no requirements that pose safety hazards, are unnecessary to achieve emission reductions, or result in duplicative burden on regulated facilities. The work practice standards in the final rule are already implemented at some of the facilities.

Furthermore, we assumed at proposal that total enclosures would be required at all facilities regardless of which option they chose. The facilities that do not operate total enclosures are unlikely to achieve fenceline ambient concentrations at or below the lead primary NAAQS. The monitoring data just mentioned and the ICR responses indicated that the facilities which have totally enclosed their processes are generally achieving ambient concentrations substantially lower than those which have not totally enclosed. Since we based our analysis at proposal on the assumption that all facilities would have to construct total enclosures and assumed that the rule would impose those costs on all sources which have not yet installed total enclosures, our cost analysis has already accounted for the cost of total enclosure. See 76 FR at 29064 and the cost impacts memo that supported the proposed rule (docket ID EPA–HQ–OAR–2011–0344–0040 at page 8). The total enclosure requirements in section 63.544 ensure that process fugitive emissions sources and other fugitive dust emissions sources will not generate fugitive emissions that escape the facility uncontrolled. The work practice standards for process fugitive emissions sources and fugitive dust emissions sources in section 63.545 ensure that fugitive dust is not generated outside of total enclosures and that fugitive dust generated inside total enclosures is not carried outside of those enclosures.

We note that one commenter's statements appear to pertain to process fugitive emissions from secondary lead smelters that are captured by enclosure hoods and vented to a control device. We agree that enclosure hoods near sources of process fugitive emissions (*e.g.*, lead taps, charging hoppers, etc.) can be an effective method to control emissions from these sources. We also recognize that these devices are important to minimize exposure of workers to lead dust. However, we note that the enclosure hoods are not 100 percent effective at controlling these emissions, and that process fugitives that are amenable to control with hoods are not the only source of fugitive emissions from secondary lead processes. We thus disagree that enclosure hoods without total enclosures represent a better alternative for controlling all fugitive emissions.

Comment: Several commenters objected to requiring monitoring of both building pressure differential and the in-draft velocity at building openings for the total enclosures and stated that the duplicate monitoring requirements are redundant and unjustified. The commenters also requested that the EPA abandon its proposed specific minimum velocity requirement at doorway openings or lower the proposed requirement of 300 feet per minute. Two commenters stated that "A number of the existing total enclosures in this industry do not meet the proposed 300 feet per minute in-draft velocity requirement, and their modification to achieve 300 feet per minute would require substantial expenditures." One commenter stated that much larger volumes of air would be exhausted from the smelter buildings and that "the greater the volume of air exhausted, the greater the emissions of lead. Therefore increasing exhaust volumes above current levels could possibly have negative impacts." The commenters requested an exemption from demonstration of compliance with the in-draft requirements for access points that are normally closed. One commenter requested clarification of the use of the terms "leeward" and "windward" in the context of the differential pressure monitoring.

One commenter stated that they have demonstrated that none of these total enclosure monitoring requirements and continuous monitoring systems are necessary to reduce actual emissions of HAP. The commenter recommended continued compliance with the original 1997 NESHAP, which requires facilities to demonstrate that total enclosures were maintained under constant negative pressure by maintaining process enclosure hoods at the prescribed face velocities. As an alternative, measurements of face velocity at doorways and windows and pressure measurements at prescribed intervals would provide a viable monitoring option.

Response: We agree with the commenters that monitoring of both building differential pressure and in-draft velocity at building openings is unnecessary. However, we disagree that continuous monitoring of differential pressure is overly prescriptive. We believe that monitoring of building differential pressure is the most accurate means by which to ensure that the building is under negative pressure at all times. This method provides direct measurements that the building is indeed maintained at negative pressure. Some commenters stated persuasively that specifying doorway velocities could require substantial additional in-draft, which could cause strain to building structures, wind chill problems for workers, and pilot lights being extinguished. We have therefore not adopted the proposed requirement to measure in-draft velocity at the openings of the total enclosures but have retained the continuous differential pressure monitoring requirement. However, we have altered the differential pressure requirement from 0.02 mm of mercury to 0.013 mm of mercury to be consistent with EPA Method 204's criteria for verification of a permanent or temporary total enclosure. With regard to the comment that increased volumes of air exhausted through control devices would increase overall emissions, it is unclear to us how directing previously uncontrolled fugitive emissions through a fabric filter would increase the overall emissions from a structure.

Comment: Several commenters objected to requiring a back-up power source for the differential pressure monitors. According to the commenters, during a power outage, the "negative pressure would not be maintained and the pressure drop monitors would simply be measuring and documenting this known and predictable fact * * *. The same information could be obtained by requiring facilities to note periods when power has been lost to the ventilation fans such that negative pressure could not be maintained." One commenter recommended requiring an uninterruptible power supply for the control device as well as the total enclosure monitoring system or removing the current requirement.

Response: We agree with the commenters' assessment that a back-up power source for the building differential pressure monitors is not needed. We also agree with the commenters' suggestion to include a recordkeeping provision for power outages that occur for the building ventilation systems. The regulatory text has been edited accordingly.

Comment: Several commenters objected to the enclosure requirement at all areas where fabric filters are handled or processed. One commenter stated that "This is impractical in that all baghouses are not and cannot be located within enclosures. Therefore, in the replacement of used bag filters, there will always be a point in which the bags must be handled in order to get them into a closed container for transport." Two commenters stated that "The first point at which used fabric filters are 'handled' is upon removal from the baghouse cell, usually on a catwalk running along the side of the baghouse. It is not appropriate to require all such areas to be placed within total enclosures. Best practices in the industry when replacing fabric filters are to place the used filter bags in sealed plastic bags or other closed containers in the cell while the filters are being replaced, but prior to removing the used filters to the catwalk."

Response: We agree that the proposed requirement to enclose all areas where fabric filters are handled or processed may be impractical at times, the enclosure of a catwalk being an example. We also agree that fabric filters cannot be enclosed under the circumstances described in these comments. We have therefore revised the regulatory text to require used fabric filters to be placed in sealed plastic bags or containers before removal from the baghouse cell.

C. Work Practice Standard Requirements for Fugitive Emissions

Comment: Several industry respondents expressed concern about the proposed requirement to perform all maintenance activities for any equipment potentially contaminated with lead bearing material inside an enclosure.

Two commenters requested clarification that once an item that is not already subject to total enclosure requirements has been cleaned, its maintenance or repair is not subject to the enclosure requirements. Both commenters also gave an example of circumstances where the best course of action would be to make an immediate repair on a leak in an elevated duct rather than wait until a temporary structure was constructed. One commenter expressed concern that inspection and maintenance of filters that are in need of removal and replacement would need to be performed within a total enclosure.

Two commenters stated that 72 hours to make repairs to any gaps or leak points in enclosures or structures was not feasible to implement. One commenter suggested that the rule "be changed to require initiation of repairs within 24 hours of discovery and completion of repairs as soon as practicable. Rather than seeking and obtaining approval for extensions from the Administrator, the source should be required to file and to keep a record listing when the problem was discovered, when the repair was initiated and when the repair was completed." Another commenter stated that "the presence of leak points is irrelevant to collection as long as the size and location of these leak points does not change over time. Once a facility documents that any total enclosure criteria (for negative pressure) are met, the presence of existing leak points is irrelevant."

One commenter requested that the EPA allow facilities to route emissions from partial or temporary enclosures to control devices that meet the performance requirements stated in the rule. According to the commenter, "This compliance option is requested, because as written, the provisions would require manufacturer's specification alone and not allow use of an otherwise compliant control device."

Response: With regard to the comment that the proposed maintenance practices were overly prescriptive, we have revised the regulatory text to require performance of maintenance "in a manner that minimizes emissions of fugitive dust" that includes several options to control fugitive emissions. With regard to the comment pertaining to inspection and maintenance of fabric filters, we have edited the regulatory text such that this enclosure requirement does not apply to inspection and maintenance practices for fabric filters.

We also agree with commenters that making prompt and timely repairs for leaks is often more effective than first constructing a total enclosure around the leak. However, we believe that the formulation to initiate repairs "as soon as practicable" is too vague. We have edited the regulatory text to require completion of repairs to enclosures within one week and inserted language allowing facilities to initiate immediate repairs of ductwork or structure leaks without an enclosure provided that the time necessary to construct a temporary enclosure would exceed the time necessary to make a temporary or permanent repair. This change ensures that the requirement is technically practicable and the most cost-effective means for fixing leaks while minimizing the period during which the leak causes emissions.

We disagree with the commenter that the presence of a leak point is irrelevant to collection as long as the size and location of these leak points do not change over time. Total enclosures are designed with openings of specific size and location to provide appropriate airflow into a building and to maintain the negative pressure at all locations. Multiple leak points at different locations of non-uniform size would be difficult to measure and document. It would also be difficult to ensure that the building negative pressure is uniform at all locations.

We agree with the commenter that facilities should be allowed to route emissions from partial temporary enclosures to existing control devices that meet the performance specification stated in the rule provided the control device has the capability to accommodate the additional air flow and that its permit accounts for the additional air flow and emissions. The regulatory text has been edited accordingly.

Comment: Several commenters expressed concerns about the requirement in the proposed rule for cleaning of building rooftops. The commenters stated that the EPA did not provide a basis to demonstrate that roof washing is effective or necessary. One commenter stated that roof cleaning was unnecessary to operate in compliance with the current lead NAAQS, and that current work practices are sufficient to meet the standard. Several commenters also stated that roof cleaning is potentially dangerous to workers and in some cases not possible due to the rooftop construction and weather conditions. Several commenters noted that the requirement unnecessarily applied at all times, even when natural precipitation makes cleaning unnecessary.

Response: We agree that the proposed roof washing requirement may not be feasible and may cause worker safety hazards in some cases, and we have therefore removed this activity from the list of required fugitive emission work practices.

Comment: Several commenters opposed the specific requirement for a mobile vacuum sweeper used for pavement cleaning when a water flush is used. The commenters stated that the EPA provides no justification for the minimum water application rate of 0.48 gallons per square yard of pavement cleaned or evidence that equipment currently used could achieve this rate. The commenters suggested that this specific requirement be replaced with a "requirement that pavement be periodically cleaned, leaving methods, and minimum water application rates to individual facilities and, as relevant, their permitting authorities." According to the commenter, "EPA should further exempt pavement cleaning on days when natural precipitation makes cleaning unnecessary or when sand or a similar material has been spread on plant roadways to provide traction on ice or snow."

Two commenters also expressed concerns that the rule requires pavement cleaning in the battery breaking, furnace, refining and casting areas when a total enclosure is not used. According to the commenters, certain locations within these areas are not capable of being cleaned on a routine basis due to safety, access, or other reasons. The commenters give an example of paved areas under process equipment as being an area that is not safe to access during operation of the equipment. One commenter also stated that roadway cleaning and washing of truck tires and undercarriages are redundant requirements with no incremental benefit.

Response: We agree with the commenters' suggestion to remove the minimum water application rate requirement from the regulatory text. We note that the proposal did include an exemption for cleaning on days when natural precipitation makes cleaning unnecessary or when sand or a similar material has been spread on plant roadways to provide traction on ice or snow. That exemption remains in the final rule. See 40 CFR 63.545(c)(2).

With regard to the comments regarding pavement cleaning requirements when total enclosures are not used, we note that the final rule requires total enclosures rather than including them as an option. Furthermore, it is our understanding that in the cases where mobile sweeping or wet washing equipment is not feasible (*e.g.*, underneath process equipment), facilities can utilize hand held vacuum equipment to clean these areas. Therefore, we do not believe it is appropriate to exempt these areas from the cleaning requirements since these areas contain fugitive lead which can be emitted and reach human and environmental receptors.

We disagree with the commenter that roadway cleaning and undercarriage washing are redundant requirements. While truck tires may be a significant source of lead bearing material on the roadway, we understand that they are not the only source. Therefore, we have maintained both requirements in the final rule.

Comment: One commenter recommended modifying the requirement to pave "all areas subject to vehicle traffic" to "all areas subject to *routine* vehicle traffic." The commenter noted that areas not subject to routine traffic do not have the potential to generate significant quantities of fugitive dust and that paving these areas would increase the amount of storm water generated.

Response: We agree with the commenter that there may be some instances where paving and cleaning a roadway is impractical. We have included an exemption in the rule for limited access and limited use roadways that access remote, infrequently used locations on the facility's property. See 40 CFR 63.545(c)(2).

Comment: Two commenters objected to the proposed frequency of inspection of the unenclosed battery storage areas. One commenter "finds this requirement to impose an administrative burden of minimal value." According to the commenter, "Spent lead acid batteries, even if accidentally broken and leaking, pose minimal potential for generation of fugitive dust containing HAPs. Inspection of these areas is typically required on a weekly basis as part of the facilities' Resource Conservation and Recovery Act obligations and such frequency is sufficient to satisfy the intent of this proposed rule as well." One commenter suggests that identifying and mitigating leaks within 72 hours will prevent generation of fugitive lead emissions. The commenter also states that it is unclear whether batteries stored in partial enclosures are exempted from the twice daily inspection requirement and proposes the following regulatory language incorporating both of these issues.

> You must inspect any batteries that are not stored in a partial or total enclosure once each day and move any broken batteries to a partial or total enclosure within 72 hours of detection. You must also clean residue from broken batteries within 72 hours of identification. Storage of batteries in trucks and railcars consistent with Department of Transportation requirements are specifically exempted from these requirements.

Response: We agree with the commenters that requiring inspection of these areas on a twice daily basis is not necessary. We have modified the regulatory text to require inspection of these areas once per week—consistent with requirements implementing the hazardous waste subtitle of RCRA (see 40 CFR 264.174 and 264.1101(c)(4) (and the EPA sees no reason to deviate from these long-standing requirements here, given that they were adopted to be "protective of human health and the environment" from management of hazardous waste)—with removal of

broken batteries within 72 hours of detection. We have also clarified that the inspection requirement does not apply to battery storage areas that are in a total enclosure. We do not believe that an exemption for storage of batteries in trucks and railcars is necessary since the inspection frequency was reduced to once per week.

Comment: One commenter objected to the requirement to collect wash water in a container that is not open to the atmosphere. The commenter stated that "Covering of these collection tanks is not necessary because lead dissolved and/or suspended in water does not have a pathway for becoming a fugitive emission."

Response: We agree with the commenter that so long as the contents in the container are wet, there should be no fugitive emissions. We have removed the requirement to collect wash water in a sealed container.

Comment: Two commenters requested changes to the requirement to transport lead bearing materials in sealed leak-proof containers. One commenter proposed that containers be "covered" rather than "sealed leak-proof" and that an exemption be made for off-road dump trucks. The suggestion was made because "sealed leak-proof containers * * * cannot be attained, but covers can be for most trucks used in such transport * * *. no approved sealing covers are made for the 30-ton, 6-wheel, off-road dump trucks used at the facility." One commenter supported the requirement for transporting lead bearing materials within an enclosure or in a sealed container, but suggested that lead bearing materials with little potential for production of fugitive lead dust from transportation should be excluded, including intact batteries, raw materials with lead content that is not considered recoverable such as iron, caustic, coal, wood, sulfur and other similar materials, and products from the recycling process.

Response: We agree that the proposed requirement for material transport should be modified. The intent of the proposed requirement was to prevent fugitive lead dust formation outside of a total enclosure. We have therefore modified the requirement at 63.545(c)(7) to read as follows:

"You must transport all lead bearing dust within closed conveyor systems or in sealed, leak-proof containers, unless the transport activities are contained within an enclosure. All other lead bearing material must be contained and covered for transport outside of a total enclosure in a manner that prevents spillage or dust formation. Intact batteries and lead ingot product are exempt from the requirement to be covered for transport."

The definition of lead bearing material in the rule clarifies that lead bearing materials must contain at least 100 ppm of lead (measured via Toxicity Characteristic Leaching Procedure (EPA Method 1311) lead test results <5 mg/l). Intact batteries and lead ingot product are excluded from this requirement.

Comment: Some commenters agreed that the secondary lead facilities operate a separation process at their battery breakers to separate polypropylene battery case material as a valuable recyclable commodity. However, not all spent lead acid batteries are amenable to separation. Certain battery types such as small sealed-lead-acid batteries and certain industrial lead-acid batteries are fed into the blast furnace without ever passing through the facility's battery breaker. These batteries are either too small or too large to be broken by the automated battery breaking equipment. One commenter requested that the EPA estimate the cost of the systems that would be required. Another commenter offered that mandatory separation could be used for facilities that are not meeting TEQ limits as one of several options to reduce emissions. Two commenters stated that the current dioxin emission levels pose no incremental health risk presented by background dioxin and that there is no valid justification for imposing this burden.

Response: Based on these comments, we have revised the proposed plastics separation work practice requirement to be specific to automotive batteries, which should be amenable to separation based on current practices used in the industry. We agree with the commenters that some industrial batteries are not easily processed in battery breakers and that the retrofits or additional equipment required to process such batteries are not justified since automotive batteries make up the vast majority of lead acid batteries processed at these facilities. We believe that plastics separation from automotive batteries is sufficient to minimize emissions of organic HAP. We further note that the use of battery breakers to separate plastics from automotive batteries is clearly a development in practices that limits emissions of organic HAP, including dioxin, and is therefore an appropriate part of a standard under CAA section 112(d)(6).

D. Emission Standards for Organic HAP From Rotary Furnaces

Comment: We received several comments on the proposed D/F and THC MACT floor limits for the rotary furnace subcategory that were based on data (two test runs, see 76 FR at 29049) from the slag-processing rotary furnace at RSR's Middletown, NY facility. One commenter stated that rotary furnace standards should not be based on emissions that are not from stand-alone rotary furnace operations. The commenter stated that the EPA should not derive standards for rotary furnaces from performance of a different source type or subcategory that includes a furnace combination (*i.e.*, reverberatory/short rotary furnace). The commenter also contends that there are insufficient data available to establish limits for D/F and THC from rotary furnaces. The commenter contends that the EPA used one source that is not representative of or similar to true rotary furnace operation to establish the limits for "rotary furnaces." The commenter stated that the emissions limit established in the proposed rule is arbitrary because it is not based on operations of rotary furnaces using lead bearing materials from lead acid batteries as feedstock.

The commenter notes that RSR's Middletown, NY facility, whose test data were used as the basis for the THC and D/F limits, only uses their rotary furnace to process one type of lead bearing material, reverberatory slag, and this furnace is not representative of the full capabilities of rotary furnace operation. The commenter notes that JCI's Florence Recycling Center plans to utilize stand-alone rotary furnaces to process lead paste, battery components, and "other materials with recoverable quantities of lead." The commenter further notes that the emissions from RSR's short rotary furnace (SRF) and drying kiln are combined, and it is unclear from information in the docket whether testing of the SRF occurred at a location prior to the combination of these exhaust streams.

The commenter also stated that JCI and RSR differ in raw materials used in the facilities' operations. RSR's Title V application for its Middletown facility indicates that RSR may process automotive, industrial, and specialty-type lead-acid batteries as well as lead bearing materials received from lead-acid battery manufacturing plants and scrap metal in its reverberatory furnace. JCI's furnace feed is from automotive and marine batteries and from lead bearing materials from other JCI facilities. The commenter contends that, since the EPA considered no data representative of a rotary furnace operation such as that which will be operated at the JCI Florence Recycling Center, a numeric limit for this category cannot be assigned.

One commenter also stated that the stack test for RSR's SRF that was used

to develop D/F and THC emission limits for "rotary furnaces" included only two successful test runs and therefore must be considered inadequate for setting emission limits since 40 CFR 63.7(e)(3) requires three test runs for compliance demonstration purposes.

One commenter supports the individual stack emission limits for THC and D/F but provides comment on the EPA's consideration of statistical variability for the rotary furnace subcategory. The commenter stated that the Upper Prediction Limit (UPL) tends to inflate the variability because the statistical procedure attempts to accommodate the highest emission measurement at the same facility and not necessarily the variability between facilities as the MACT floor is intended to achieve. Additionally, the UPL is very dependent on the number of valid samples. The commenter contends that, when a suitable number of samples have been collected, the 99 percent confidence limit (CL) represents a range for which there is 99 percent certainty that the interval contains the true mean. The commenter suggests that caution be used when determining a MACT floor from limited test data and that the 99 percent CL is more appropriate for this particular industry.

One commenter noted that the EPA did not consider a secondary lead smelting facility in Puerto Rico that operates a stand-alone rotary furnace. The commenter contends that even if it were appropriate to set MACT floor emission rates or standards for rotary furnaces, the EPA would have to obtain and consider data from the Puerto Rico facility. According to the commenter, failure to consider data from the facility "undermines the RTR Proposed Rule and any attempt by EPA to establish emission standards for the rotary furnace subcategory." The commenter contends that the EPA should issue a separate ICR for the Puerto Rico facility and publish a supplemental notice of proposed rulemaking that takes into account the emission information for this facility.

Response: The EPA agrees that rotary furnaces fueled by natural gas could be different from rotary furnaces operating using different fuel types, and that rotary furnaces processing slag could be different types of rotary furnaces than those processing lead acid batteries. More basically, the EPA simply has insufficient data on which to promulgate organic HAP standards for rotary furnaces. The proposed standards for THC and D/F were based on less than one single complete test, consisting only of two test runs from the natural gas fueled rotary furnace processing slag. See 76 FR at 29049–29050. (A complete test consists of three test runs.) When calculating variability using a limited dataset (in this case, the two test runs) the effect of variability can be substantial. Id. The proposed THC and D/F standards likewise were based on two test runs and similarly reflected enormous statistical variability due to the limited data. Id. at 29049/1. The EPA does not believe that these data are sufficient to adopt a standard even for the rotary furnace which was tested, much less a rotary furnace which may be different. Accordingly, we are not adopting standards for organic HAP emissions from rotary furnaces at this time and instead we intend to issue CAA section 114 information requests to sources operating rotary furnaces to obtain more representative emission data and plan to propose standards for organic HAP in a future action. However, we note that the lead emission standards included in this action do apply to rotary furnaces processing slag or lead acid batteries.

E. The EPA's Risk Assessment Supporting the Proposed Rule

Comment: Two commenters stated that the EPA's methodology is unreliable and incorrect. The commenters stated that the EPA overestimated the baseline fugitive emissions for the Exide Frisco facility whose (faulty) estimates then became the basis for estimating all other facilities' fugitive emission rates. The commenter stated that the EPA scaled Exide's reported fugitive emissions of 0.296 tpy for the blast and reverberatory furnace fugitive emissions to 0.32 tpy based on the assumption that fugitives would not be on the same operating schedule as process emissions. The commenter contends that this scaling is inappropriate since furnace fugitives can only occur when the associated process furnaces are operating. The commenter further stated that the EPA also double-counted the fugitives of 0.32 tpy by assigning the value to each of the blast and reverberatory furnaces, despite the fact that Exide reported the value as combined emissions for both the reverberatory and blast furnace.

Response: The commenter is correct in both respects. The EPA has accordingly adjusted its calculation of the fugitive emissions from Exide's Frisco facility (thereby reducing the facility's fugitive dust emissions estimate) and adjusted the emissions estimates for each facility to reflect the revised estimate of the Frisco facility. The resulting risk results have also been adjusted. We note that the updated emissions estimates and risk results did not substantively alter our decisions under section 112(f). The modeling showed 9 of 15 facilities above the lead NAAQS, down from 12 of 14 facilities at proposal. The maximum modeled lead concentration in the source category decreased from about 23 times the NAAQS to about 16 times the NAAQS. We still find that risks from this source category are not acceptable and that revisions under section 112(f)(2) are therefore required, and further find that it is necessary under section 112(d)(6) to revise the standards for fugitive emissions considering the developments in cost-effective control technologies for their control.

Comment: Three commenters stated that the EPA's multipathway risk estimates are incorrect because they relied on incorrect dioxin and furan emissions from Exide's Frisco, Texas facility. The commenters contend that a dioxin and furan test conducted in October 2010 at the Frisco facility revealed an emissions rate of 6.2E–08 tons/year on a toxic equivalency quotient (TEQ) basis, 69 times lower than the estimate used by the EPA. One commenter noted that the exact effect that the difference in emissions would have on the calculated risks is unknown since the EPA has not placed the full methodology behind its multipathway risk calculations in the record. However, the commenter noted that assuming the relationship between emissions and risk is approximately linear, the EPA's calculated risk would be approximately 69 times lower than that estimated at proposal and less than 1 in a million. The commenter further requested that the EPA disclose its multipathway risk calculation methodology and allow for public notice-and-comment. Another commenter stated that the EPA's overestimation of dioxin and furan emissions may lead to unwarranted public concern about the Frisco facility. The commenter requested that the EPA include a clarifying explanation regarding the Frisco emissions data and the lower multipathway risk in the final rule as well as in the risk assessment document.

Response: As noted in previous responses, the final risk assessment reflects updated emission information received during the public comment period for the proposed rule. We also note that the updated dioxin/furan test data were not made available to the EPA, despite repeated requests, until June 2011. With respect to the estimated emissions of D/F, the commenter is correct that EPA overestimated these emissions at proposal by a factor of 69 for the reasons stated. Considering this updated emissions information, the EPA

estimates that multipathway risk associated with the Exide Frisco facility is less than 1 in a million (and so contributes very little to the estimates of risk posed by this source category, and is not a driver of the determination that risks from this source category are unacceptable). See *Residual Risk Assessment for the Secondary Lead Smelting Source Category,* available in the docket, at pages 32–33.

This additional information does not warrant any reopening of the proposed rule or comment period, however. First, the EPA fully disclosed its multipathway risk methodology; the commenter's assertions to the contrary are simply mistaken. Thus, the risk assessment document along with its appendices was available in the docket for the proposed rulemaking and describes in detail the methodology used in the assessment. See the *Residual Risk Assessment for the Secondary Lead Smelting Source Category,* at page 10, available in the docket. Also see docket ID EPA–HQ–OAR–2011–0344–0037 for a thorough discussion of the EPA's human health multipathway risk assessment methodology.

Second, the new information reinforces the tentative conclusion the EPA reached at proposal: risks associated with emissions of dioxin and furans from the secondary lead source category are not primary drivers in the unacceptable risks from this source category (*i.e.* dioxin and furan emissions are not the reason that risks from secondary lead smelter emissions are unacceptable). See 76 FR at 29055/2. The new analysis reinforces that risks posed by dioxin and furan emissions are acceptable, since emission levels are 69 times less than estimated at proposal (when risks from CDD and CDFs were already considered to be at an acceptable level). Thus, this already acceptable level of risk is less than estimated and less than one in a million. The EPA does not agree that further comment on this issue is warranted, since further comment would not have a practical effect on the rule.[7]

Comment: One commenter stated that the EPA inappropriately summed risks from the inhalation and multipathway risk assessments at the Exide Frisco facility. The commenter noted that it is impossible for the person with the highest chronic inhalation cancer risk to also be the same person with the highest individual multipathway cancer risk since the two MIR values are location dependent and are at locations that are widely separated. The commenter further noted that the EPA has indicated in other contexts that when populations are exposed via more than one pathway, the combination of exposures across pathways must also represent a reasonable maximum exposure.

Response: The EPA disagrees with the commenter. While highly unlikely (and noted as being highly unlikely in the risk assessment document), it is theoretically possible for the person with the highest chronic inhalation cancer risk to also be the same person with the highest individual multipathway cancer risk. The EPA notes that the multipathway risk assessment does not provide a specific location for the MIR; thus, it is possible (although highly unlikely) that the person with the highest inhalation MIR is also consuming fish (at the fish ingestion rates described in the multipathway report) from the theoretically contaminated lake. That being said, however, we note that considering updated emissions information for this facility, updated multipathway results indicate multipathway risk associated with the Exide Frisco facility are well below one in a million. Considering these updated results, multipathway risk would not appreciable add to any inhalation risk associated with this facility.

Comment: Commenter 94 stated that the EPA improperly calculated the inhalation cancer MIR for the Exide Frisco facility in a vacant field to the north of the facility within the facility's property line. The commenter noted that the lifetime cancer risk of the MEI cannot be at a location within the facility property line.

Response: The commenter is correct and the EPA has corrected the receptor location resulting in a change in the results in the final risk assessment. The MIR for this facility is now located at a populated census block (based on the 2001 census).

F. Miscellaneous Changes to the Regulatory Text

Comment: Three commenters requested that the EPA replace the term "modified source" with "reconstructed source." Neither the proposed rule nor the EPA's general Part 63 regulations define the term "modified source." The term is defined in the CAA, but that definition would require a source to install maximum achievable control technology and impose a "new source" requirement like CEMS on a modified source, rather than appropriately imposing the existing source provisions that do not require installation of a CEMS.

Response: The term "modified source" appeared in the proposed rule at 40 CFR 63.548(l) under the proposed requirement to install a CEMS for measuring lead emissions on all new or modified sources. We agree with the commenter that the terminology of "reconstructed" source would be more appropriate for this requirement and have changed the regulatory language accordingly.

Comment: Three commenters requested clarification of the term "affected source" as used in the proposed rule. The proposed rule uses the terms "new sources", "existing source" and "modified source" without clarifying whether it is referring to secondary lead smelters generally, or to potential emissions sources within secondary lead smelters. There is a seeming contradiction between the use of the term "affected source" in the proposed rule and the definition in 40 CFR Part 63, Subpart A general provisions. One commenter also understands that the terms "new sources" and "existing sources", as used in the proposed rule, are consistent with the definitions as used in CAA § 112(a). The commenter "understands EPA intends to address any addition of units to an 'existing source' consistent with the provisions of the CAA" and understands that the analysis as explained in *Nine Metal Fabrication and Finishing Area Source Categories, 40 CFR Part 63 (6X) NESHAP, Questions and Answers,* April 2011 would apply with respect to implementation of any amendments to subpart X requirements. The Q&A explains that the "CAA uses the word 'source' to mean the entire facility in terms of the classification of 'new' vs. 'existing' whereas for the Subpart 6X rule, what is referred to as the 'affected source' is actually one of the processes at the facility".

Response: The EPA has clarified the application of these terms in the final rule. The definition in 40 CFR part 63, subpart A requires each relevant standard to define the "affected source," as the collection of equipment, activities, or both within a single contiguous area and under common control that is included in a CAA section 112(c) source category or subcategory for which a section 112(d) standard or other relevant standard is established pursuant to CAA section 112 unless a different definition is warranted based on a published justification as to why this definition would result in significant administrative, practical, or implementation problems and why the

[7] The comment that EPA's standards for dioxin and furans do not result in significant risk reduction is misplaced given that the EPA is not adopting any risk-based (*i.e.*, section 112(f)(2)) standards based on the need for reduction of emissions of dioxin and furan.

different definition would resolve those problems. We have adopted a definition of "affected source" in this rulemaking as any of the listed individual sources at a secondary lead smelter. This application of the term "affected source" is the same as was used in the 1997 NESHAP for secondary lead. The term "affected source" is used in the final rule primarily in the context of new sources. This definition is appropriate for the secondary lead source category because the chief source of emissions from these facilities are the furnaces, and as these furnaces are replaced or reconstructed, the replacement equipment would be subject to the standard for a new source.

A "new source" has also been defined as any affected source at a secondary lead facility that undergoes construction or reconstruction after May 19, 2011, the date of the proposed CAA section 112(f)(2) and 112(d)(6) rules. A building that is constructed for the purpose of controlling fugitive emissions from an existing source is not considered to be a new source because it is effectively a control device for fugitive emissions.

Comment: One commenter noted that the last sentence in the current definition of "Materials storage and handling area" has been deleted in the proposed definition. This sentence reads: "Materials storage and handling area does not include areas used exclusively for storage of blast furnace slag." The commenter disagreed with the EPA's assessment that this is a minor change. "EPA should provide an explanation of what changed circumstances justify a new rule." Two other commenters requested that the definition be modified to exclude the transfer of raw materials of any type in enclosed conveyors. The commenter stated that "as currently worded, the enclosure requirement proposed would apply to handling of fabric filter dust in enclosed conveyors, containers, or in wet slurried form, which is unnecessary." The commenter suggested revising the definition to include the following: "Material storage and handling area shall not include any closed containers or enclosed mechanical conveyors."

Response: A definition of "lead bearing material" has been added to the final rule. Rather than include or exclude any one particular material in the definition of "materials storage and handling area" based on the originating process, this definition establishes lead content as the criterion for determining whether materials must be handled in such a manner as to prevent lead dust formation. The definition of "materials storage and handling area" remains essentially unchanged from the definition in the proposed rule.

Fugitive dust formation has been identified as the major contributor to ambient lead concentrations near secondary lead smelters. Piles where lead bearing materials are stored were identified as one of the major sources of fugitive lead emissions. However, there was no definition for lead-bearing material in the proposed rule that could be used to make a determination of which materials needed to be handled in a manner that prevents dust formation. By adding a definition of "lead bearing material" to the rule, we have clarified and quantified the definition of "materials storage and handling area."

The EPA is using the Toxicity Characteristic Leaching Procedure (TCLP), EPA Method 1311 to measure which materials are lead-bearing, and using the characteristic level of 5.0 mg/l (in the extract from the test) as the specific level for being lead-bearing. See 40 CFR 261.24. This assures that only materials with at least 100 ppm total lead will be considered to be 'lead-bearing'. See EPA Method 1311 section 2.2 which describes that the liquid to solid ratio of material tested should be 20:1 (*i.e.* 5 mg/l in the TCLP extract is equal to at least 100 ppm in the material being tested). The specific definition of lead bearing material chosen ensures that materials that contain relatively substantial amounts of lead (0.01 percent) are included while minimizing additional testing burden for facilities who must determine what does or does not meet the definition. Testing burden is minimized because facilities already use the TCLP to determine whether or not the wastes they manage are hazardous, pursuant to subtitle C of the Resource Conservation and Recovery Act. Imposing a different threshold for defining material as "lead bearing" could thus impose duplicative or conflicting requirements between subpart X and other regulatory regimes. Furthermore, the TCLP is a test protocol which includes a grinding step, which is a conservative measure of determining whether a material could generate fugitive emissions. See Method 1311 steps 7.1.3 and 7.2.10.

To address the concern that fabric filter dust in enclosed conveyors, containers or wet slurries must be additionally handled only inside an enclosure, we have added an exemption from the enclosure requirement for materials that are "lead bearing" but are not expected to generate fugitive lead dust. While these materials do contain lead in amounts that could otherwise meet the definition of lead bearing material, they are either in a stabilized form that will not create fugitive dust or in a container that prevents fugitive dust formation. These materials include: lead ingot products, stormwater and wastewater, intact batteries, lead bearing material that is stored in closed containers or enclosed mechanical conveyors, and clean battery casing material.

Comment: One commenter requested a change to the definition of "plant roadway" specifically to exclude finished lead product storage areas and roadways or traffic areas located within enclosed buildings.

Response: We accept the commenter's suggestion to exclude roadways or traffic areas located within enclosed buildings from the definition of "plant roadway." However, we do not believe that it is appropriate to exclude finished lead product storage areas since these areas may be located in close proximity to areas that may require cleaning (*e.g.*, slag storage areas).

Comment: One commenter requested a change to the definition of process vent. As currently drafted, it appears overly broad and could lead to confusion concerning the ventilation systems that must be tested.

Response: We have made revisions to the regulatory text to clarify that the term "process vent" includes various process vents and vents from buildings containing lead bearing material. Vents from office or other non-process areas are not considered to be process vents.

Comment: Two comments were received on the terminology used for a lead CEMS. According to the commenter, "Paragraph 63.548(m) specifies that lead CEMS be 'continuous emission *rate* monitors.' The standard is a concentration standard, not an emission rate standard, so the term "continuous emission *rate* monitor" is not appropriate". Since flow and concentration monitors are needed to calculate compliance with the flow weighted average, one commenter recommended a requirement for flow and concentration monitors rather than citing a type of monitoring system that is not applicable to the standard.

Response: We agree with the commenter that the term continuous emissions *rate* monitor is not appropriate. We have replaced the term "continuous emissions rate monitor" with "continuous emissions monitoring system."

Comment: Two commenters noted that the term "accidental release" is not defined in the rule. The commenters recommended that the EPA use the CERCLA reportable quantity threshold of 10 pounds to define an accidental

release of lead-containing dust. Two commenters recommended that the requirement to initiate cleaning within one hour of a release be changed to require that the facility initiate cleaning activities within one hour *after discovery* of an accidental release.

Response: We accept the commenters' suggestion to use the CERCLA reportable quantity threshold of 10 pounds to define an accidental release of lead-containing dust. We also accept the commenters' suggestion to require initiation of cleaning within one hour of discovery of an accidental release.

Comment: One commenter recommended that the definition of "maintenance activity" be changed from "any of the following routine maintenance and repair activities that generate fugitive lead dust:" to "any of the following maintenance and repair activities *when they* generate fugitive lead dust:"

Response: We do not agree with the commenter's proposed change to the definition of "maintenance activity." If this definition was adopted, the facility would be allowed to proceed with a maintenance activity and then, if the activity began generating dust, controls would need to be adopted but otherwise-controllable lead emissions would be released to ambient air. However, we have modified the definition to read "any of the following routine maintenance and repair activities that could generate fugitive lead dust." This definition ensures that proactive, rather than reactive, actions would be taken for activities with the potential to generate lead dust.

Comment: One commenter stated that a definition of lead-bearing material should be added and should include such characteristics as the material should be semi-granular, have a lead content of greater than 10 percent, and produce visible fugitive emissions when handled or transported.

Response: As noted above, we have added a definition of lead-bearing material to the regulatory text. However, we believe that a 10 percent lead content is too high. We have defined lead-bearing material in the rule as material with lead content of 5 mg/l or greater as measured by the TCLP (Method 1311), which means that materials would need to contain at least 100 ppm of lead. This is equivalent to the toxicity characteristic level for a hazardous waste containing lead as defined at 40 CFR 261.24.

Comment: One commenter noted that 40 CFR 63.544(d) of the proposed rule makes reference to the requirements in subsections (d)(1) through (d)(4). However, as the commenter points out, there are eight subsections applicable to 40 CFR 63.544(d) and subsection (d)(2) further refers to meeting requirements through (d)(8).

Response: The EPA agrees with the commenter and has made the suggested change in the regulatory text at 40 CFR 63.544(d).

Comment: One commenter noted that proposed 40 CFR 63.543(i) requires that sources conduct testing for process vents, "* * * under such conditions as the administrator specifies based on representative performance of the affected source for the period being tested." The commenter requested that the EPA replace this "cumbersome" language with "* * * under normal operating conditions."

Response: We have modified the text to require sources to conduct testing "under maximum representative operating conditions for the process." The term maximum is included to ensure that the testing occurs during a time period of full production at the facility that is representative of normal operation. This language allows sources to develop test conditions which approximate the variability they can reasonably encounter during normal operation. Parametric monitoring requirements, based on parameters measured during the performance test, would then reasonably reflect this operating variability and afford the source flexibility in its day-to-day operation. *Cf. Cement Kiln Recycling Coalition* v. *EPA,* 255 F.855, 866–67 (DC Cir. 2001) (upholding use of such data to set MACT standards under CAA section 112(d)(3)).

Comment: One commenter noted that Table 3 of the proposed rule is improperly labeled, "table 3 to Subpart X of Part 60—Toxic Equivalency Factors." As the commenter points out, the table is included in 40 CFR part 63, not 40 CFR part 60.

Response: The EPA agrees with the commenter and has made the suggested change to Table 3 of the proposed rule.

Comment: Two commenters pointed out that there is a typographical error in Equation 2 of the proposed rule at 40 CFR 63.543(c). The definition of the term C_{ELI} includes the word lead, though the equation is not applicable to lead.

Response: The EPA agrees with the commenter and has adjusted the definition of the term C_{ELI} in Equation 2 of 40 CFR 63.543(c) accordingly.

G. Emission Testing Methods and Frequency

Comment: Two commenters stated their support for biannual testing for well performing facilities. One commenter contends that the East Penn facility currently conducts biannual testing for lead and still maintains compliance with the lead NAAQS and applicable subpart X emission standards. The commenter further argued that the EPA has not demonstrated any environmental benefits associated with annual testing versus biannual testing for well controlled facilities. The commenter contends that the East Penn facility has made strategic decisions to invest capital resources to reduce lead emissions and that the removal of the biannual testing exemption would unnecessarily increase the annual operating costs of the facility.

Response: We agree with the commenter that a biannual testing exemption for well performing facilities can be retained in this NESHAP. We have added an exemption for any stacks that report a lead concentration of 0.1 mg/dscm or lower allowing biannual testing. The concept of decreased testing frequency for well-performing sources was discussed in the proposal as a part of the fenceline monitoring approach (see 76 FR at 29057).

Comment: Two commenters disagreed with the annual testing requirement for total hydrocarbons (THC). One commenter stated that since the risk assessment did not identify significant risks drivers among the organic HAP represented by THC, the THC testing should be conducted concurrently with the dioxin and furan tests every 5 years with continuous compliance demonstrated via afterburner temperature monitoring. Another commenter stated that requiring annual THC tests is redundant and unnecessary if a CEMS is installed and operated per 40 CFR 63.543(k).

Response: We disagree with the commenter that THC testing should be conducted on the same schedule as dioxins and furans. Testing for THC is substantially less expensive than testing for dioxins and furans and we do not believe annual THC testing presents an unnecessary burden. However, we have added an exemption allowing biannual testing of THC for any stack that reports concentrations that are less than half of the applicable emissions limit. Annual stack testing is obviously not required if a THC CEMS is used.

Comment: Three commenters stated that the EPA should allow facilities to use EPA Method 12 for lead compounds to calculate compliance with the process vent limitations in order to be consistent with testing requirements that exist in many facility permits.

Response: We agree that facilities should be given the option of using EPA

Method 12. The regulatory text has been edited accordingly.

Comment: Three commenters stated that the BLDS exemption for baghouses equipped with HEPA filters should be retained. One commenter stated that to install BLDS's on HEPA filtered stacks is excessive and unwarranted. The commenter also believes that annual stack testing for sources equipped with HEPA filtration is not necessary. Another commenter argued that the cost associated with using BLDS is not commensurate with their limited ability. The commenter stated that BLDS's are inherently reactive whereas baghouses equipped with HEPA filtration actually prevent emissions in the event of a bag failure. Further, the commenter argued that HEPA secondary collection pressure differential is an effective method to monitor baghouse performance. The commenter contends that the BLDS requirement will pose an unnecessary and redundant burden on facilities that proactively chose to install HEPA filtration systems and that the proposed revisions are a disincentive for facilities to install HEPA filters. Finally, the commenter stated that the proposed BLDS requirement and the elimination of the BLDS exemption for HEPA filters are arbitrary and not supported by test data.

Response: We agree with the commenters that baghouses equipped with HEPA filters do not need bag leak detection systems as well. The measurement of pressure drop across a HEPA filter provides the indicia of superior performance for determining continuous compliance. However, we disagree that sources should be exempt from annual stack testing based solely on the use of a HEPA filter. The emission standard includes calculation of a facility-wide emission average and testing the process vents subject to that limit is needed to determine compliance. Monitoring pressure drop across HEPA filters is a means for determining continuous compliance, similar to a bag leak detection system in baghouses without HEPA filters. In both cases, periodic stack tests are necessary to ensure that lead emissions are below the applicable emission standard. However, we note that we have included a biannual testing exemption for stacks that report lead concentrations less than 0.1 mg/dscm.

H. Startup, Shutdown, and Malfunction

Comment: One commenter expressed concerns related to the total hydrocarbon (THC) standard during start-up periods. According to the commenter, it will be impossible to meet the minimum temperature at which compliance with the THC standard has been demonstrated during startup of a furnace. The blast furnace crucible must be heated for up to 12 hours before raw materials can be charged. The reverberatory furnace cold startups occur over an extended period also. There is no introduction of feedstock during the warm-up process and, therefore, no emissions of process-related THC emissions. Emissions during this time period will consist entirely of combustion products associated with the fuels natural gas and foundry coke. The afterburner or post combustion system are equipped with rudimentary burners that provide supplementary heat but rely on the excess heat contained within the combined furnace exhaust gases during production operations to achieve an afterburner temperature that assures the efficient combustion of the process off-gases. The afterburner supplementary burners are not sufficient to maintain the required temperature during furnace startup and shutdown sequences. The proposed revisions to subpart X should include definitions of startup and shutdown for collocated blast and reverberatory furnaces that clearly define when alternative THC standards would apply and how compliance with an alternative standard is monitored.

Response: The EPA has revised this final rule to require sources to meet a work practice standard that requires the development of standard operating procedures designed to minimize emissions of THC for each start-up and shutdown scenario anticipated for all units subject to THC emission limits. We considered whether temperature (the metric used to determine continuous compliance for the THC standard in this rule) or performance testing and enforcement of numeric emission limits would be practicable during periods of startup and shutdown. The EPA determined that there are a number of significant technical challenges associated with emissions measurements of THC emissions during periods of startup and shutdown for this industry. These challenges make establishing and complying with numerical emissions limits impracticable.

There are multiple factors informing this decision. Temperature is obviously an inappropriate measure to determine continuous compliances for these furnaces during periods of startup and shutdown when the furnaces are being heated during startup (or cooled during shutdown) from ambient to the steady state operating temperature. The furnaces are heated during periods of startup through slow feeding of natural gas and small amounts of coke with no lead acid batteries fed to the furnace. It is impossible for furnace exhaust to be maintained within the window prescribed by 40 CFR 63.548(h)(4) during periods of startup and shutdown. However, the inability to maintain this temperature in secondary lead smelter furnace exhaust does not indicate high emissions of THC during these periods. In fact, the emissions are likely minimal because there are no plastics being fed to the furnace and minimal fuel use (mostly natural gas). Temperature is thus not the appropriate measure of continuous compliance during these periods and we are unaware of another metric that can be used to determine continuous compliance with a numerical standard for these furnaces during startup and shutdown. In terms of staff scheduling, test crews would have to be on-site and ready to begin THC testing at the beginning of a period of startup or shutdown, have multiple test crews on site for startup or shutdown periods lasting longer than 12 hours, and be prepared to stop and restart measurements to coincide with process trips that can occur during startup and shutdown of secondary lead smelting furnaces. Since startups and shutdowns of these furnaces are not necessarily scheduled long in advance, scheduling such testing to coincide with the beginning of startup or shutdown periods would require having testing crews on-site nearly full time. These staff resource issues would dramatically increase the cost of testing during startup and shutdown periods.

For these technical and economic reasons, we have determined that conducting manual test methods during these secondary lead furnace startup or shutdown periods for THC to be impracticable within the meaning of CAA section 112(h)(2)(B). As a result, we have established a separate work practice standard for emissions of THC during periods of startup and shutdown. This work practice standard requires the development of standard operating procedures designed to minimize emissions of THC for each start-up and shutdown scenario anticipated for all units subject to THC limits.

This startup and shutdown work practice applies only to the THC emission limits. We have no reason to provide startup or shutdown provisions for emissions of lead from any source because the fabric filters used to control particulate and lead emissions are not less effective during startup or shutdown periods (nor would we expect sources to have any difficulty meeting the lead standard since lead-bearing feed is not charged during either startup

or shutdown conditions). Additionally, the metrics for determining continuous compliance with these standards are appropriate for periods of startup and shutdown. Therefore, we have established the separate work practice standard only for THC for periods of startup and shutdown.

During these periods, we do not believe dioxins and furans can form because there are no chlorinated plastics or flame-retardants being fed as these materials are only introduced as impurities with the lead feed material. Therefore, we have not included a standard for dioxins and furans during periods of startup and shutdown because these pollutants are not emitted.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 63.2). The EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times.

VI. Summary of Cost, Environmental, and Economic Impacts

A. What are the affected facilities?

We anticipate that the 15 secondary lead smelting facilities currently or recently operating in the continental United States and Puerto Rico as well as one facility currently under construction in South Carolina will be affected by this final rule.

B. What are the air quality impacts?

The EPA estimated the emissions reductions that are expected to result from these final amendments to the 1997 NESHAP compared to the 2009 baseline emissions estimates calculated based on ICR data. The ICR data and RTR emissions memo are available in the docket to this action. A detailed documentation of the analysis can be found in the document in the docket titled: *Cost Impacts of the Revised NESHAP for the Secondary Lead Smelting Source Category.*

Emissions of lead and arsenic from secondary lead smelters have declined over the last 15 years as a result of federal rules, state rules and on the industry's own initiative. The final rule will cut lead and arsenic emissions by an estimated 68 percent from current actual emission levels based on the ICR data collected for this rulemaking. The final rule will result in estimated annual lead emissions reductions of 7.2 tpy from process and process fugitive sources and annual lead emissions reductions of 6.4 tpy from fugitive dust sources from 2009 baseline emissions (for a total annual reduction of 13.6 tons per year). The expected annual reduction in total metal HAP [8] is 8.2 tpy from process and process fugitive sources and the expected annual reduction is 7.2 tpy from fugitive dust sources (total annual metal HAP reductions are estimated at 15.4 tons). We estimate that these controls will also reduce emissions of particulate matter (PM) (combined total of fine and coarse PM) by 135 tpy.

Based on the emissions data available to the EPA, we believe that all facilities will be able to comply with the final emissions limits for THC and D/F without additional controls. However, we expect that emissions reductions will occur due to increased temperatures of afterburners and from improved work practices. Nevertheless, it is difficult to estimate accurate reductions from these actions and, therefore, we are not providing quantified estimates of reductions for THC and D/F.

C. What are the cost impacts?

As a result of this final rule, certain secondary lead smelting facilities are expected to incur capital costs for the following types of control measures: replacement of existing baghouses with new, higher-performing baghouses, replacement of bags in existing baghouses with better-performing materials, construction of new enclosures for processes not currently enclosed, modification of partially enclosed structures to meet the requirements of total enclosure, and installation of fabric filters on enclosures.

The capital costs for each facility were estimated based on the number and types of upgrades we estimate that facility will require. Each facility was evaluated for its ability to meet the final limits for lead emissions, THC emissions, D/F emissions, and fugitive dust emissions. The memorandum titled: *Cost Impacts of the Revised NESHAP for the Secondary Lead Smelting Source Category* includes a complete description of the cost estimate methods used for this analysis and is available in the docket.

The majority of the capital costs estimated for compliance with this action are for purchasing new enclosures and the associated control devices that would be required for these enclosures. For each facility, we estimated the square footage of new enclosures required based on the size of enclosures currently in place compared to facilities that we considered to be totally enclosed with a similar production capacity. We further assumed that the facilities that required a substantial degree of new enclosure would re-configure their facilities, particularly the storage areas, to reduce the footprint of areas subject to total enclosure requirements.

Based on our analysis of the facility configurations, seven facilities were considered already to be totally enclosed. Two facilities are currently installing enclosure structures and equipment that we anticipate will meet the requirements. Consequently, the capital costs do not include estimates for these nine facilities. We estimate that the remaining six facilities will require new building installations, thereby incurring capital costs. For the one facility currently under construction, we estimated one additional baghouse would be required.

Typical enclosure costs were estimated using information and algorithms from the Permanent Total Enclosures chapter in the EPA Air Pollution Control Cost Manual. New baghouse costs were estimated using a model based primarily on the cost information for recent baghouse installations submitted by facilities in the ICR survey. The total capital cost estimate for the enclosures, the ductwork system, and control devices at the seven facilities is approximately $38 million, at an annualized cost of $6.4 million in 2009 dollars (an average of about $1 million per facility).

We also estimated annual costs for the required work practices in this action. Based on the ICR survey information, we estimated that additional costs would be required to implement the work practices at 12 of the 16 facilities. The total annual costs to implement the fugitive emissions work practices are approximately $3 million per year.

For compliance with the stack lead concentration limit, we compared each stack emission point's lead concentration (reported to the EPA under the ICR) to the requirement of 1.0 mg/dscm of lead for any one stack. If the reported concentration exceeded 0.5 mg/dscm (one half the standard), we assumed that the facility would either

[8] Total metal HAP consists of antimony, arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

upgrade the baghouse with new bags and additional maintenance or completely replace the baghouse, depending on the age of the baghouse (as explained further below). This cost estimate presents an upper-end estimate of the cost impacts of the final rule that assumes facilities will strive to operate well below the standard to ensure process variability does not cause emission rates approaching the maximum level allowed by the standard. If the baghouse was less than 10 years old and the lead concentration in the outlet was not appreciably over one half the standard (*i.e.*, 0.5 mg/dscm), we assumed that the baghouse would require maintenance and bag replacement. If the baghouse was more than 10 years old and the lead concentration was appreciably over the standard, we assumed the baghouse would be replaced. We then compared each facility's emissions with the flow-weighted, facility-wide concentration limit of 0.20 mg/dscm using the assumption that baghouses needing replacement based on the 1.0 mg/dscm individual stack limit would be replaced with units that performed at least as well as the average baghouse identified in our data set. These analyses indicate that nine baghouses would need to be replaced, and two baghouses would require additional maintenance. To estimate costs, we used a model based primarily on the cost information submitted in the ICR for recent baghouse installations in this industry. We assumed an increase in maintenance cost based on more frequent bag changes (from once every 5 years to once every 2 years). The total capital cost for nine new baghouses at five facilities is estimated to be approximately $11.5 million, and total annual costs were estimated to be approximately $2.7 million.

New limits are being promulgated for THC and D/F emissions from reverberatory and electric furnaces. We anticipate all operating affected units will be able to meet the limits without installing additional controls; however, we have estimated additional costs of $260,000 per year for facilities to increase the temperature of their existing afterburners to ensure continuous compliance with the standards. (We also considered this additional energy use as part of our analysis of whether the standards are warranted under CAA section 112(d)(6). See *Cost Impacts of the Revised NESHAP for the Secondary Lead Smelting Source Category*, available in docket ID EPA–HQ–OAR–2011–0344, at page 7.)

The capital cost estimated for additional differential pressure monitors for total enclosures is $106,000. The cost for all additional monitoring and recordkeeping requirements, including the baghouse monitoring, is estimated at $791,000.

The total annualized costs for the final rule are estimated at $13.4 million (2009 dollars). Table 5 of this preamble provides a summary of the estimated costs and emissions reductions associated with the final amendments to the Secondary Lead Smelting NESHAP presented in today's action. More detail on the estimated costs of today's final rule can be found in *Cost Impacts of the revised NESHAP for the Secondary Lead Smelting Source Category*, available in the docket ID EPA–HQ–OAR–2011–0344.

TABLE 5—ESTIMATED COSTS AND REDUCTIONS FOR THE PROMULGATED STANDARDS IN THIS ACTION

Final amendment	Estimated capital cost ($MM)	Estimated annual cost ($MM)	Total HAP emissions reductions (tons per year)	Cost effectiveness in $ per ton total HAP reduction ($ per pound)
Revised stack lead emissions limit ...	11.5	2.7	8.2 of metal HAP[a] (7.2 of which is lead).	$0.33 MM per ton, ($170 per pound).
Total enclosure of fugitive emissions sources.	38	6.4	5.2 of metal HAP[a] (4.6 of which is lead).	$1.0 MM per ton, ($500 per pound).
Fugitive control work practices	0	3.0	2.0 of metal HAP[a] (1.8 of which is lead).	$1.5 MM per ton, ($750 per pound).
THC and D/F concentration limits	0	0.3	29.6[b]	$0.01 MM per ton.
Additional testing and monitoring	0.3	0.79	N/A	N/A.

[a] Metal HAP consisting of antimony, arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium.
[b] Based on total organic HAP reductions as a co-benefit of compliance with standards for dioxins and furans.

The EPA notes that the cost effectiveness of the controls for stack emissions of metal HAP are within the range of values the agency has determined to be reasonable in other section 112 rules. Indeed, EPA determined that a value of $175 per pound of metal HAP removed was reasonable when determining standards for the iron and steel foundry source category, an area source standard reflecting the less rigorous Generally Available Control Technology under section 112(d)(5). See 73 FR at 249. Thus, EPA regards the cost effectiveness of the standards for metal HAP here as reasonable, for purposes of the standards adopted pursuant to sections 112(f)(2) (ample margin of safety determination) and 112(d)(6). The measures required to control fugitive emissions are also cost effective, based largely on the fact that much of the industry has implemented some or all of the measures required in this final rule. The cost effectiveness for THC and D/F is presented as a point of information. Since those standards are MACT floor standards adopted pursuant to sections 112(d)(3), considerations of cost and cost-effectiveness played no part in EPA's consideration.

D. What are the economic impacts?

We performed an economic impact analysis for secondary lead consumers and producers nationally. Most secondary lead producers will incur annual compliance costs of much less than 1 percent of their sales, but one firm will incur costs of greater than 1 percent. Both demand and supply in this sector are generally inelastic to price changes as shown in the Economic Impact Analysis at page 4. Thus, if producers could pass through the entire cost of the rule to consumers, we would expect prices to increase by no more than one percent, with no change in output. Conversely, if producers could not pass through any of the cost by increasing the price, we would expect output to decline by less than one percent.

Hence, the overall economic impact of this proposed rule should be low on most of the affected industry and its consumers. For more information, please refer to the Economic Impact Analysis for this rulemaking that is in docket ID EPA–HQ–OAR–2011–0344.

E. What are the benefits?

The estimated reductions in lead emissions that will be achieved by this final rule will provide significant benefits to public health. For example, the EPA's 2008 Regulatory Impact Analysis (RIA) that was completed for the lead NAAQS (which is available in the docket for this action and also on the EPA's Web site) [9] described monetized benefits calculated for that action associated with reduced exposure to lead.

As noted in that RIA, there were also several other lead-related health effects for which the EPA was unable to quantify a monetized benefit—particularly among adults. These potential impacts included hypertension, non-fatal strokes, reproductive effects and premature mortality, among others.

When viewed in this context, the reductions in concentrations of ambient lead that will be achieved with this RTR for secondary lead smelters are expected to provide important benefits to both children and adults. The EPA did not quantify these benefits because this rule did not trigger the requirement for conducting an RIA under Executive Order 12866, in addition to resource and data limitations for this rule. However, as noted at proposal, this rule should result in areas attaining the lead NAAQS where the secondary lead smelting source dominates the areas' ambient lead concentrations. See 76 FR at 29063–64. Although these standards are not adopted to implement the lead NAAQS, and rest on legal and policy justifications that are unrelated to the requirements for adopting, revising, and implementing a NAAQS (*e.g.*, CAA sections 112(d)(2), (3), 6 and CAA section 112(f)(2) as opposed to CAA sections 107–110), nonetheless these rules will aid in the attainment of the lead NAAQS.[10]

In addition to the benefits likely to be achieved for lead reductions, we also estimate that this final RTR rule will achieve about 39 to 63 tons of reductions in $PM_{2.5}$ emissions as a co-benefit of the HAP reductions annually. See *Development of the RTR Emissions Dataset for the Secondary Lead Smelting Source Category* at section 8.3, which is available in the docket for information on how the $PM_{2.5}$ emission reductions were calculated based on total PM reductions. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$ exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009).[11] When adequate data and resources are available and an RIA is required, the EPA generally quantifies several health effects associated with exposure to $PM_{2.5}$ (*e.g.*, U.S. EPA, 2010) [12]. These health effects include premature mortality for adults and infants, cardiovascular morbidities such as heart attacks, hospital admissions, and respiratory morbidities such as asthma attacks, acute and chronic bronchitis, hospital and emergency department visits, work loss days, restricted activity days, and respiratory symptoms. Although the EPA has not quantified certain outcomes including adverse effects on birth weight, pre-term births, pulmonary function and other cardiovascular and respiratory effects, the scientific literature suggests that exposure to $PM_{2.5}$ is also associated with these impacts (U.S. EPA, 2009).

Finally, the final rule will provide human health benefits through reductions in arsenic and cadmium emissions, as well as reductions in emissions of organic HAP (including dioxins and furans).

VII. Statutory and Executive Order Reviews

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

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action." This action is a significant regulatory action because it raises novel legal and policy issues. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 1686.09. The information collection requirements are not enforceable until OMB approves them. The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emissions standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

We are promulgating new paperwork requirements to the Secondary Lead Smelting source category in the form of stack testing for THC and D/F as described in 40 CFR 63.543(h)–(k). In conjunction with setting THC limits for reverberatory and electric furnaces, additional monitoring and recordkeeping is required for furnace outlet temperature on these units. We believe temperature monitors currently exist in these locations and that the facilities will not incur a capital cost due to this requirement (and received no comments to indicate otherwise). Additionally, increased monitoring is required for demonstrating negative pressure in all total enclosures. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to this ICR to show what the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports and records for any individual incident, including the root cause analysis, totals $3,141 and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emissions

[9] *http://www.epa.gov/ttn/ecas/regdata/RIAs/finalpbriach5.pdf.*

[10] It is possible that SIPs may require some of the same types of controls on these sources (or may rely on the controls in these rules as part of a control strategy). EPA cannot, of course, pre-judge the SIP process. What is clear is that this rule should contribute significantly to attainment of the lead NAAQS.

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

[12] U.S. Environmental Protection Agency (U.S. EPA). 2010. *Regulatory Impact Analysis for the Proposed Federal Transport Rule.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. <*http://www.epa.gov/ttn/ecas/regdata/RIAs/proposaltrria_final.pdf*>.

limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense.

Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions for which an affirmative defense to penalties might be asserted. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus we believe the number of instances in which source operators might be expected to assert the affirmative defense will be extremely small. For this reason, we estimate no more than 2 or 3 such occurrences for all sources subject to subpart X over the 3-year period covered by this ICR. We expect to gather information on such events in the future and will revise this estimate as better information becomes available. We estimate 16 regulated entities are currently subject to subpart X and will be subject to all standards. The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) for these amendments to subpart X (Secondary Lead Smelting) is estimated to be $790,000 per year. This includes 1,600 labor hours per year at a total labor cost of $347,000 per year, and total non-labor capital and operation and maintenance (O&M) costs of $440,000 per year. This estimate includes performance tests, notifications, reporting, and recordkeeping associated with the new requirements for front-end process vents and back-end process operations. The total burden for the federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 1,150 hours per year at a total labor cost of $52,000 per year. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When these ICRs are approved by OMB, the agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control numbers for the approved information collection requirements contained in the final rules.

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 final rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

For this source category, which has the NAICS code 331419 (*i.e.*, Secondary Smelting and Refining of Nonferrous Metal (except copper and aluminum)), the SBA small business size standard is 750 employees according to the SBA small business standards definitions. We have estimated the cost impacts and have determined that the impacts do not constitute a significant economic impact on a substantial number of small entities (see: *Small Business Analysis for the Secondary Lead Smelting Source Category,* which is available in the docket for this action).

After considering the economic impacts of today's final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Two of the eight parent companies affected are considered a small entity per the definition provided in this section. However, we estimate that this action will not have a significant economic impact on those companies (see: *Small Business Analysis for the Secondary Lead Smelting Source Category).* All other affected parent companies are not small businesses according to the SBA small business size standard for the affected NAICS code (NAICS 331419).

Although this final rule will not have a significant economic impact on a substantial number of small entities, the EPA nonetheless has tried to reduce the impact of this rule on small entities. To reduce the impacts, we are promulgating stack limits for lead that allow sources to meet a standard based on aggregated emissions that are based on a weighted average approach (with each stack required to achieve a specified minimum level of control) and have been established at the least stringent levels that we estimate will still result in acceptable risks to public health with an ample margin of safety. Moreover, the compliance testing requirements were established in a way that minimizes the costs for testing and reporting while still providing the agency the necessary information needed to ensure continuous compliance with the standards. For more information, please refer to *Small Business Analysis for the Secondary Lead Smelting Source Category,* which is available in docket ID EPA–HQ–OAR–2011–0344.

D. Unfunded Mandates Reform Act

This action does not contain a federal mandate under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for state, local, or tribal governments or the private sector. The action would not result in expenditures of $100 million or more for state, local, and tribal governments, in aggregate, or the private sector in any 1 year. The action imposes no enforceable duties on any state, local or tribal governments or the private sector. Thus, this action is not subject to the requirements of sections 202 or 205 of the UMRA.

This action is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments nor does it impose obligations upon them.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the

distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. These final rules primarily affect private industry, and do not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to this action.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

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

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is not economically significant as defined in Executive Order 12866. However, the agency does believe there is a disproportionate risk to children due to current emissions of lead from this source category. Children living near secondary lead smelters are the subpopulation most susceptible to effects of air-borne lead, as explained in detail in Section V.A above. The primary NAAQS for lead targets protection to this population, and is a reasonable measure for evaluating acceptability of risk here, again as explained in Section V.A. Modeled ambient air lead concentrations, based on actual emission levels, from about 9 of the 15 facilities in this source category are in excess of the NAAQS for lead. Also, the results of the demographic analysis indicate that of the 84,000 people exposed to a cancer risk greater than 1-in-1 million, the age 0 to 17 demographic percentage (of 30 percent) is 3 percentage points higher than the corresponding national percentage for this demographic group (of 27 percent). This suggests that children may be at a slightly disproportionate risk of exposure to cancer risks from this source category. However, the control measures promulgated in this notice will result in lead concentration levels at or below the lead NAAQS at all facilities, thereby mitigating the risk of future adverse health effects to children. See Section V.A of this preamble and the *Residual Risk Assessment for the Secondary Lead Smelting Source Category*, which is available in the docket for this action, for discussions of post-control risks.

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

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse energy effect on the supply, distribution, or use of energy. This action will not create any new requirements for sources in the energy supply, distribution, or use sectors. Further, we have concluded that these final rules are not likely to have any adverse energy effects (and indeed, rejected certain types of control options, such as standards based on use of wet electrostatic precipitators, in part because of adverse energy implications).

I. National Technology Transfer and Advancement Act

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

This action involves technical standards. The EPA requires use of ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses" for its manual methods of measuring the oxygen or carbon dioxide content of the exhaust gas. These parts of ASME PTC 19.10–1981 are acceptable alternatives to EPA Method 3B. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990.

Under 40 CFR 63.7(f) and 40 CFR 63.8(f) of subpart A of the General Provisions, a source may apply to the EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications, or procedures in the final rule.

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

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

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

To examine the potential for any environmental justice issues that might be associated with each source category, we evaluated the distributions of HAP related cancer and non-cancer risks across different social, demographic, and economic groups within the populations living near the facilities where these source categories are located. The development of demographic analyses to inform the consideration of environmental justice issues in EPA rulemakings is evolving.

In the case of Secondary Lead Smelting, we focused on populations within 50 km of the 15 facilities in this source category with emissions sources subject to the MACT standard. More specifically, for these populations we evaluated exposures to HAP that could result in cancer risks of 1-in-1 million or greater, or population exposures to ambient air lead concentrations above the level of the NAAQS for lead. We compared the percentages of particular demographic groups within the focused populations to the total percentages of those demographic groups nationwide. The results of this analysis are documented in the technical report: *Risk and Technology Review—Final Analysis of Socio-Economic Factors for Populations Living Near Secondary Lead Smelting Facilities* which can be found in the docket for this rulemaking. The actions in today's final rule will significantly decrease the risks due to HAP emissions from this source

category for all demographic groups and mitigate any disproportionate risks due to those emissions.

K. Congressional Review Act

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

List of Subjects for 40 CFR Part 63

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

Dated: December 16, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, part 63 of title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

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

■ 2. Section 63.14 is amended by revising paragraph (p)(2) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(p) * * *

(2) Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, EPA–454/R–98–015, September 1997, IBR approved for §§ 63.548(e)(4), 63.7525(j)(2), and 63.11224(f)(2).

* * * * *

■ 3. Revise subpart X to read as follows:

Subpart X—National Emission Standards for Hazardous Air Pollutants From Secondary Lead Smelting

Sec.

63.541 Applicability.
63.542 Definitions.
63.543 What are my standards for process vents?
63.544 What are my total enclosure standards?
63.545 What are my standards for fugitive dust sources?
63.546 Compliance dates.
63.547 Test methods.
63.548 Monitoring requirements.
63.549 Notification requirements.
63.550 Recordkeeping and reporting requirements.
63.551 Implementation and enforcement.
63.552 Affirmative defense to civil penalties for exceedance of emissions limit during malfunction.
Table 1 to Subpart X of Part 63—General Provisions Applicability to Subpart X
Table 2 to Subpart X of Part 63—Emissions Limits for Secondary Lead Smelting Furnaces
Table 3 to Subpart X of Part 63—Toxic Equivalency Factors

Subpart X—National Emission Standards For Hazardous Air Pollutants From Secondary Lead Smelting

§ 63.541 Applicability.

(a) You are subject to this subpart if you own or operate any of the following affected sources at a secondary lead smelter: Blast, reverberatory, rotary, and electric furnaces; refining kettles; agglomerating furnaces; dryers; process fugitive emissions sources; buildings containing lead bearing materials; and fugitive dust sources. The provisions of this subpart do not apply to primary lead processors, lead refiners, or lead remelters.

(b) Table 1 to this subpart specifies the provisions of subpart A of this part that apply to owners and operators of secondary lead smelters subject to this subpart.

(c) If you are subject to the provisions of this subpart, you are also subject to title V permitting requirements under 40 CFR parts 70 or 71, as applicable.

(d) Emissions standards in this subpart apply at all times.

§ 63.542 Definitions.

Terms used in this subpart are defined in the Clean Air Act, in subpart A of this part, or in this section as follows:

Affected source means any of the following sources at a secondary lead smelter: Blast, reverberatory, rotary, and electric furnaces; refining kettles; agglomerating furnaces; dryers; process fugitive emissions sources; buildings containing lead bearing materials; and fugitive dust sources.

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

Agglomerating furnace means a furnace used to melt into a solid mass flue dust that is collected from a baghouse.

Bag leak detection system means an instrument that is capable of monitoring particulate matter (dust) loadings in the exhaust of a baghouse in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, transmittance or other effect to monitor relative particulate matter loadings.

Battery breaking area means the plant location at which lead-acid batteries are broken, crushed, or disassembled and separated into components.

Blast furnace means a smelting furnace consisting of a vertical cylinder atop a crucible, into which lead-bearing charge materials are introduced at the top of the furnace and combustion air is introduced through tuyeres at the bottom of the cylinder, and that uses coke as a fuel source and that is operated at such a temperature in the combustion zone (greater than 980 Celsius) that lead compounds are chemically reduced to elemental lead metal.

Blast furnace charging location means the physical opening through which raw materials are introduced into a blast furnace.

Collocated blast furnace and reverberatory furnace means operation at the same location of a blast furnace and a reverberatory furnace where the vent streams of the furnaces are mixed before cooling, with the volumetric flow rate discharged from the blast furnace being equal to or less than that discharged from the reverberatory furnace.

Dryer means a chamber that is heated and that is used to remove moisture from lead-bearing materials before they are charged to a smelting furnace.

Dryer transition equipment means the junction between a dryer and the charge hopper or conveyor, or the junction between the dryer and the smelting furnace feed chute or hopper located at the ends of the dryer.

Electric furnace means a smelting furnace consisting of a vessel into which reverberatory furnace slag is introduced and that uses electrical energy to heat the reverberatory furnace slag to such a temperature (greater than 980 Celsius) that lead compounds are reduced to elemental lead metal.

Fugitive dust source means a stationary source of hazardous air pollutant emissions at a secondary lead smelter that is not associated with a specific process or process fugitive vent or stack. Fugitive dust sources include, but are not limited to, roadways, storage piles, lead bearing material handling transfer points, lead bearing material transport areas, lead bearing material storage areas, other lead bearing material process areas, and buildings.

Furnace and refining/casting area means any area of a secondary lead smelter in which:

(1) Smelting furnaces are located;

(2) Refining operations occur; or

(3) Casting operations occur.

Lead alloy means an alloy in which the predominant component is lead.

Lead bearing material means material with a lead content equal to or greater than 5 mg/l as measured by EPA Method 1311 (Under Method 1311, only materials with at least 100 ppm lead will be considered to be lead bearing).

Leeward wall means the furthest exterior wall of a total enclosure that is opposite the windward wall.

Maintenance activity means any of the following routine maintenance and repair activities that could generate fugitive lead dust:

(1) Replacement or repair of refractory, or any internal or external part of equipment used to process, handle or control lead-containing materials.

(2) Replacement of any duct section used to convey lead-containing exhaust.

(3) Metal cutting or welding that penetrates the metal structure of any equipment, and its associated components, used to process lead-containing material such that lead dust within the internal structure or its components can become fugitive lead dust.

(4) Resurfacing, repair or removal of ground, pavement, concrete, or asphalt.

Materials storage and handling area means any area of a secondary lead smelter in which lead-bearing materials (including, but not limited to, broken battery components, reverberatory furnace slag, flue dust, and dross) are stored or handled between process steps including, but not limited to, areas in which materials are stored in open piles, bins, or tubs, and areas in which material is prepared for charging to a smelting furnace.

Natural draft opening means any permanent opening in an enclosure that remains open during operation of the facility and is not connected to a duct in which a fan is installed.

New source means any affected source at a secondary lead smelting facility the construction or reconstruction of which is commenced after May 19, 2011. A building that is constructed for the purpose of controlling fugitive emissions from an existing source is not considered to be a new source.

Partial enclosure means a structure comprised of walls or partitions on at least three sides or three-quarters of the perimeter surrounding stored materials or process equipment to prevent the entrainment of particulate matter into the air.

Pavement cleaning means the use of vacuum equipment, water sprays, or a combination thereof to remove dust or other accumulated material from the paved areas of a secondary lead smelter.

Plant roadway means any area of a secondary lead smelter outside of a total enclosure that is subject to vehicle traffic, including traffic by forklifts, front-end loaders, or vehicles carrying whole batteries or cast lead ingots. Excluded from this definition are employee and visitor parking areas, provided they are not subject to traffic by vehicles carrying lead-bearing materials.

Pressurized dryer breaching seal means a seal system connecting the dryer transition pieces which is maintained at a higher pressure than the inside of the dryer.

Process fugitive emissions source means a source of hazardous air pollutant emissions at a secondary lead smelter that is associated with lead smelting or refining, but is not the primary exhaust stream from a smelting furnace, and is not a fugitive dust source. Process fugitive emissions sources include, but are not limited to, smelting furnace charging points, smelting furnace lead and slag taps, refining kettles, agglomerating furnaces, and drying kiln transition pieces.

Process vent means furnace vents, dryer vents, agglomeration furnace vents, vents from battery breakers, vents from buildings containing lead bearing material, and any ventilation system controlling lead emissions.

Refining kettle means an open-top vessel that is constructed of cast iron or steel and is indirectly heated from below and contains molten lead for the purpose of refining and alloying the lead. Included are pot furnaces, receiving kettles, and holding kettles.

Reverberatory furnace means a refractory-lined furnace that uses one or more flames to heat the walls and roof of the furnace and lead-bearing scrap to such a temperature (greater than 980 Celsius) that lead compounds are chemically reduced to elemental lead metal.

Rotary furnace (also known as a rotary reverberatory furnace) means a furnace consisting of a refractory-lined chamber that rotates about a horizontal axis and that uses one or more flames to heat the walls of the furnace and lead-bearing scrap to such a temperature (greater than 980 Celsius) that lead compounds are chemically reduced to elemental lead metal.

Secondary lead smelter means any facility at which lead-bearing scrap material, primarily, but not limited to, lead-acid batteries, is recycled into elemental lead or lead alloys by smelting.

Shutdown means the period when no lead bearing materials are being fed to the furnace and smelting operations have ceased during which the furnace is cooled from steady-state operating temperature to ambient temperature.

Smelting means the chemical reduction of lead compounds to elemental lead or lead alloys through processing in high-temperature (greater than 980 Celsius) furnaces including, but not limited to, blast furnaces, reverberatory furnaces, rotary furnaces, and electric furnaces.

Startup means the period when no led bearing materials have been fed to the furnace and smelting operations have not yet commenced during which the furnace is heated from ambient temperature to steady-state operating temperature.

Total enclosure means a containment building that is completely enclosed with a floor, walls, and a roof to prevent exposure to the elements and to assure containment of lead bearing material with limited openings to allow access and egress for people and vehicles. The total enclosure must provide an effective barrier against fugitive dust emissions such that the direction of air flow through any openings is inward and the enclosure is maintained under constant negative pressure.

Vehicle wash means a device for removing dust and other accumulated material from the wheels, body, and underside of a vehicle to prevent the inadvertent transfer of lead contaminated material to another area of a secondary lead smelter or to public roadways.

Wet suppression means the use of water, water combined with a chemical surfactant, or a chemical binding agent to prevent the entrainment of dust into the air from fugitive dust sources.

Windward wall means the exterior wall of a total enclosure that is most impacted by the wind in its most prevailing direction determined by a wind rose using available data from the

closest representative meteorological station.

§ 63.543 What are my standards for process vents?

(a) For existing sources, you must maintain the concentration of lead compounds in any process vent gas at or below 1.0 milligrams of lead per dry standard cubic meter (0.00043 grains of lead per dry standard cubic foot). You must maintain the flow-weighted average concentration of lead compounds in vent gases from a secondary lead smelting facility at or below 0.20 milligrams of lead per dry standard cubic meter (0.000087 grains of lead per dry standard cubic foot).

(1) You must demonstrate compliance with the flow weighted average emissions limit on a 12-month rolling average basis, calculated monthly using the most recent test data available.

(2) Until 12 monthly weighted average emissions rates have been accumulated, calculate only the monthly average weighted emissions rate.

(3) You must use Equation 1 of this section to calculate the flow-weighted average concentration of lead compounds from process vents:

$$C_{FWA} = \frac{\sum_{i=1}^{n} F_i \times C_i}{\sum_{i}^{n} F_i} \quad \text{(Eq. 1)}$$

Where:

C_{FWA} = Flow-weighted average concentration of all process vents.
n = Number of process vents.
F_i = Flow rate from process vent *i* in dry standard cubic feet per minute, as measured during the most recent compliance test.
C_i = Concentration of lead in process vent *i*, as measured during the most recent compliance test.

(4) Each month, you must use the concentration of lead and flow rate obtained during the most recent compliance test performed prior to or during that month to perform the calculation using Equation 1 of this section.

(5) If a continuous emissions monitoring system (CEMS) is used to measure the concentration of lead in a vent, the monthly average lead concentration and monthly average flow rate must be used rather than the most recent compliance test data.

(b) For new sources that begin construction or reconstruction after May 19, 2011 you must maintain the concentration of lead compounds in any process vent gas at or below 0.20 milligrams of lead per dry standard cubic meter (0.000087 grains of lead per dry standard cubic foot).

(c) You must meet the applicable emissions limits for total hydrocarbons and dioxins and furans from furnace sources specified in Table 2 of this subpart. There are no standards for dioxins and furans during periods of startup and shutdown.

(d) If you combine furnace emissions from multiple types of furnaces and these furnaces do not meet the definition of collocated blast and reverberatory furnaces, you must calculate your emissions limit for the combined furnace stream using Equation 2 of this section.

$$C_{EL} = \frac{\sum_{i=1}^{n} F_i \times C_{ELi}}{\sum_{i}^{n} F_i} \quad \text{(Eq. 2)}$$

Where:

C_{EL} = Flow-weighted average emissions limit (concentration) of combined furnace vents.
n = Number of furnace vents.
F_i = Flow rate from furnace vent i in dry standard cubic feet per minute.
C_{Eli} = Emissions limit (concentration) of pollutant in furnace vent i as specified in Table 2 of this subpart.

(e) If you combine furnace emissions with the furnace charging process fugitive emissions and discharge them to the atmosphere through a common emissions point, you must demonstrate compliance with the applicable total hydrocarbons concentration limit specified in paragraph (c) of this section at a location downstream from the point at which the two emissions streams are combined.

(f) If you do not combine the furnace charging process fugitive emissions with the furnace process emissions, and discharge such emissions to the atmosphere through separate emissions points, you must maintain the total hydrocarbons concentration in the exhaust gas at or below 20 parts per million by volume, expressed as propane and corrected to 4 percent carbon dioxide.

(g) Following the initial performance or compliance test to demonstrate compliance with the lead emissions limits specified in paragraph (a) or (b) of this section, you must conduct performance tests according to the schedule in paragraph (g)(1) or (2) of this section.

(1) Conduct an annual performance test for lead compounds from each process vent (no later than 12 calendar months following the previous compliance test), unless you install and operate a CEMS meeting the requirements of § 63.8.

(2) If an annual compliance test demonstrates that a process vent emitted lead compounds at 0.10 milligram of lead per dry standard cubic meter or less during the time of the annual compliance test, you may submit a written request to the Administrator applying for an extension of up to 24 calendar months from the previous compliance test to conduct the next compliance test for lead compounds.

(h) Following the initial performance or compliance test to demonstrate compliance with the total hydrocarbons emissions limits in paragraphs (c) and (f) of this section, you must conduct an annual performance test for total hydrocarbons emissions from each process vent that has established limits for total hydrocarbons (no later than 12 calendar months following the previous compliance test), unless you install and operate a CEMS meeting the requirements of § 63.8. If an annual compliance test demonstrates that a process vent emitted total hydrocarbons at less than 50 percent of the allowable limit during the time of the annual compliance test, you may submit a written request to the Administrator applying for an extension of up to 24 calendar months from the previous compliance test to conduct the next compliance test for total hydrocarbons.

(i) Following the initial performance or compliance test to demonstrate compliance with the dioxins and furans emissions limits specified in paragraph (c) of this section, you must conduct a performance test for dioxins and furans emissions from each process vent that has established limits for dioxins and furans at least once every 6 years following the previous compliance test.

(j) You must conduct the performance tests specified in paragraphs (g) through (i) of this section under maximum representative operating conditions for the process. During the performance test, you may operate the control device at maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(k) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for

minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(l) If you own or operate a unit subject to emission limits in Table 2 of this subpart, you must minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures, if available. You must develop and follow standard operating procedures designed to minimize emissions of total hydrocarbon for each startup or shutdown scenario anticipated. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures, if available, and the standard operating procedures designed to minimize emissions of total hydrocarbons.

(m) In addition to complying with the applicable emissions limits for dioxins and furans listed in Table 2 to this subpart, you must operate a process to separate plastic battery casing materials from all automotive batteries prior to introducing feed into a furnace.

§ 63.544 What are my total enclosure standards?

(a) You must operate the process fugitive emissions sources and fugitive dust sources listed in paragraphs (a)(1) through (9) of this section in a total enclosure that is maintained at negative pressure at all times and vented to a control device designed to capture lead particulate. The total enclosure must meet the requirements specified in paragraph (c) of this section.

(1) Smelting furnaces.

(2) Smelting furnace charging areas.

(3) Lead taps, slag taps, and molds during tapping.

(4) Battery breakers.

(5) Refining kettles, casting areas.

(6) Dryers.

(7) Agglomerating furnaces and agglomerating furnace product taps.

(8) Material handling areas for any lead bearing materials except those listed in paragraph (b) of this section.

(9) Areas where dust from fabric filters, sweepings or used fabric filters are processed.

(b) Total enclosures are not required in the following areas: lead ingot product handling areas, stormwater and wastewater treatment areas, intact battery storage areas, areas where lead bearing material is stored in closed containers or enclosed mechanical conveyors, and areas where clean battery casing material is handled.

(c) You must construct and operate total enclosures for the sources listed in paragraph (a) of this section as specified in paragraphs (c)(1) and (2) of this section. The total enclosure must be free of significant cracks, gaps, corrosion or other deterioration that could cause lead bearing material to be released from the primary barrier. Measures must be in place to prevent the tracking of lead bearing material out of the unit by personnel or by equipment used in handling the material. An area must be designated to decontaminate equipment and any rinsate must be collected and properly managed.

(1) You must ventilate the total enclosure continuously to ensure negative pressure values of at least 0.013 mm of mercury (0.007 inches of water).

(2) You must maintain an inward flow of air through all natural draft openings.

(d) You must inspect enclosures and facility structures that contain any lead-bearing materials at least once per month. You must repair any gaps, breaks, separations, leak points or other possible routes for emissions of lead to the atmosphere within one week of identification unless you obtain approval for an extension from the Administrator before the repair period is exceeded.

§ 63.545 What are my standards for fugitive dust sources?

(a) You must prepare, and at all times operate according to, a standard operating procedures manual that describes in detail the measures that will be put in place and implemented to control the fugitive dust emissions from the sources listed in paragraphs (a)(1) through (7) of this section.

(1) Plant roadways.

(2) Plant buildings.

(3) Accidental releases.

(4) Battery storage area.

(5) Equipment maintenance.

(6) Material storage areas.

(7) Material handling areas.

(b) You must submit the standard operating procedures manual to the Administrator or delegated authority for review and approval when initially developed and any time changes are made.

(c) The controls specified in the standard operating procedures manual must at a minimum include the requirements specified in paragraphs (c)(1) through (7) of this section.

(1) *Cleaning.* Where a cleaning practice is specified, you must clean by wet wash or a vacuum equipped with a filter rated by the manufacturer to achieve 99.97 percent capture efficiency for 0.3 micron particles in a manner that does not generate fugitive lead dust.

(2) *Plant roadways and paved areas.* You must pave all areas subject to vehicle traffic and you must clean the pavement twice per day, except on days when natural precipitation makes cleaning unnecessary or when sand or a similar material has been spread on plant roadways to provide traction on ice or snow. Limited access and limited use roadways such as unpaved roads to remote locations on the property may be exempt from this requirement if they are used infrequently (no more than one round trip per day).

(3) *Accidental releases.* You must initiate cleaning of all affected areas within one hour after detection of any accidental release of lead dust that exceeds 10 pounds (the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) reportable quantity for lead at 40 CFR 302.4).

(4) *Battery storage areas.* You must inspect any batteries that are not stored in a total enclosure once each week and move any broken batteries to an enclosure within 72 hours of identification. You must clean residue from broken batteries within 72 hours of identification.

(5) *Materials storage and handling areas.* You must wash each vehicle at each exit of the material storage and handling areas. The vehicle wash must include washing of tires, undercarriage and exterior surface of the vehicle followed by vehicle inspection.

(6) *Equipment maintenance.* You must perform all maintenance activities that could generate lead dust in a manner that minimizes emissions of fugitive dust. This must include one or more of the following:

(i) Performing maintenance inside a total permanent enclosure maintained at negative pressure.

(ii) Performing maintenance inside a temporary enclosure and use a vacuum system either equipped with a filter rated by the manufacturer to achieve a capture efficiency of 99.97 percent for 0.3 micron particles or routed to an existing control device permitted for this activity.

(iii) Performing maintenance inside a partial enclosure and use of wet suppression sufficient to prevent dust formation.

(iv) Decontamination of equipment prior to removal from an enclosure.

(v) Immediate repair of ductwork or structure leaks without an enclosure if the time to construct a temporary

enclosure would exceed the time to make a temporary or permanent repair, or if construction of an enclosure would cause a higher level of emissions than if an enclosure were not constructed.

(vi) Activities required for inspection of fabric filters and maintenance of filters that are in need of removal and replacement are not required to be conducted inside of total enclosures. Used fabric filters must be placed in sealed plastic bags or containers prior to removal from a baghouse.

(7) *Material transport.* You must collect and transport all lead bearing dust (*i.e.* lead bearing material which is a dust) within closed conveyor systems or in sealed, leak-proof containers unless the collection and transport activities are contained within a total enclosure. All other lead bearing material must be contained and covered for transport outside of a total enclosure in a manner that prevents spillage or dust formation. Intact batteries and lead ingot product are exempt from the requirement to be covered for transport.

(d) Your standard operating procedures manual must specify that records be maintained of all pavement cleaning, vehicle washing, and battery storage inspection activities performed to control fugitive dust emissions.

(e) You must pave all grounds on the facility or plant groundcover sufficient to prevent wind-blown dust. You may use dust suppressants on unpaved areas that will not support a groundcover (*e.g.*, roadway shoulders, steep slopes, limited access and limited use roadways).

(f) As provided in § 63.6(g), as an alternative to the requirements specified in this section, you can demonstrate to the Administrator (or delegated State, local, or Tribal authority) that an alternative measure(s) is equivalent or better than a practice(s) described in this section.

§ 63.546 Compliance dates.

(a) For affected sources that commenced construction or reconstruction on or before May 19, 2011, you must demonstrate compliance with the requirements of this subpart no later than January 6, 2014.

(b) For affected sources that commenced construction or reconstruction after May 19, 2011, you must demonstrate compliance with the requirements of this subpart by January 5, 2012 or upon startup of operations, whichever is later.

§ 63.547 Test methods.

(a) You must use the test methods from appendix A of part 60 as listed in paragraphs (a)(1) through (5) of this section to determine compliance with the emissions standards for lead compounds specified in § 63.543(a) and (b).

(1) EPA Method 1 at 40 CFR part 60, appendix A–1 to select the sampling port location and the number of traverse points.

(2) EPA Method 2 at 40 CFR part 60, appendix A–1 or EPA Method 5D at 40 CFR part 60, appendix A–3, section 8.3 for positive pressure fabric filters, to measure volumetric flow rate.

(3) EPA Method 3, 3A, or 3B at 40 CFR part 60, appendix A–2 to determine the dry molecular weight of the stack gas.

(4) EPA Method 4 at 40 CFR part 60, appendix A–3 to determine moisture content of the stack gas.

(5) EPA Method 12 or Method 29 at 40 CFR part 60, appendix A–8 to determine compliance with the lead compound emissions standards. The minimum sample volume must be 2.0 dry standard cubic meters (70 dry standard cubic feet) for each run. You must perform three test runs and you must determine compliance using the average of the three runs.

(b) You must use the following test methods in appendix A of part 60 listed in paragraphs (b)(1) through (4) of this section, as specified, to determine compliance with the emissions standards for total hydrocarbons specified in § 63.543(c) through (f).

(1) EPA Method 1 at 40 CFR part 60, appendix A–1 to select the sampling port location and number of traverse points.

(2) The Single Point Integrated Sampling and Analytical Procedure of Method 3B to measure the carbon dioxide content of the stack gases when using either EPA Method 3A or 3B at 40 CFR part 60, appendix A–2.

(3) EPA Method 4 at 40 CFR part 60, appendix A–3 to measure moisture content of the stack gases.

(4) EPA Method 25A at 40 CFR part 60, appendix A–7 to measure total hydrocarbons emissions. The minimum sampling time must be 1 hour for each run. You must perform a minimum of three test runs. You must calculate a 1-hour average total hydrocarbons concentration for each run and use the average of the three 1-hour averages to determine compliance.

(c) You must correct the measured total hydrocarbons concentrations to 4 percent carbon dioxide as specified in paragraphs (c)(1) through (3) of this section.

(1) If the measured percent carbon dioxide is greater than 0.4 percent in each compliance test, you must determine the correction factor using Equation 2 of this section.

$$F = \frac{4.0}{CO_2} \qquad \text{(Eq. 2)}$$

Where:

F = Correction factor (no units).

CO_2 = Percent carbon dioxide measured using EPA Method 3A or 3B at 40 CFR part 60, appendix A–2, where the measured carbon dioxide is greater than 0.4 percent.

(2) If the measured percent carbon dioxide is equal to or less than 0.4 percent, you must use a correction factor (F) of 10.

(3) You must determine the corrected total hydrocarbons concentration by multiplying the measured total hydrocarbons concentration by the correction factor (F) determined for each compliance test.

(d) You must use the following test methods in appendix A of part 60 listed in paragraphs (d)(1) through (5) of this section, as specified, to determine compliance with the emissions standards for dioxins and furans specified in § 63.543(c).

(1) EPA Method 1 at 40 CFR part 60, appendix A–1 to select the sampling port location and the number of traverse points.

(2) EPA Method 2 at 40 CFR part 60, appendix A–1 or EPA Method 5D at 40 CFR part 60, appendix A–3, section 8.3 for positive pressure fabric filters to measure volumetric flow rate.

(3) EPA Method 3A or 3B at 40 CFR part 60, appendix A–2 to determine the oxygen and carbon dioxide concentrations of the stack gas.

(4) EPA Method 4 at 40 CFR part 60, appendix A–3 to determine moisture content of the stack gas.

(5) EPA Method 23 at 40 CFR part 60, appendix A–7 to determine the dioxins and furans concentration.

(e) You must determine the dioxins and furans toxic equivalency by following the procedures in paragraphs (e)(1) through (3) of this section.

(1) Measure the concentration of each dioxins and furans congener shown in Table 3 of this subpart using EPA Method 23 at 40 CFR part 60, appendix A–7. You must correct the concentration of dioxins and furans in terms of toxic equivalency to 7 percent O_2 using Equation 3 of this section.

$$Cadj = \frac{Cmeas(20.9-7)}{(20.9-\%O2)} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Dioxins and furans concentration adjusted to 7 percent oxygen.

C_{meas} = Dioxins and furans concentration measured in nanograms per dry standard cubic meter.

(20.9–7) = 20.9 percent oxygen—7 percent oxygen (defined oxygen correction basis).

20.9 = Oxygen concentration in air, percent.

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

(2) For each dioxins and furans congener measured as specified in paragraph (e)(1) of this section, multiply the congener concentration by its corresponding toxic equivalency factor specified in Table 3 to this subpart.

(3) Sum the values calculated as specified in paragraph (e)(2) of this section to obtain the total concentration of dioxins and furans emitted in terms of toxic equivalency.

§ 63.548 Monitoring requirements.

(a) You must prepare, and at all times operate according to, a standard operating procedures manual that describes in detail procedures for inspection, maintenance, and bag leak detection and corrective action plans for all baghouses (fabric filters or cartridge filters) that are used to control process vents, process fugitive, or fugitive dust emissions from any source subject to the lead emissions standards in §§ 63.543, 63.544, and 63.545, including those used to control emissions from building ventilation.

(b) You must submit the standard operating procedures manual for baghouses required by paragraph (a) of this section to the Administrator or delegated authority for review and approval.

(c) The procedures that you specify in the standard operating procedures manual for inspections and routine maintenance must, at a minimum, include the requirements of paragraphs (c)(1) through (9) of this section.

(1) Daily monitoring of pressure drop across each baghouse cell.

(2) Weekly confirmation that dust is being removed from hoppers through visual inspection, or equivalent means of ensuring the proper functioning of removal mechanisms.

(3) Daily check of compressed air supply for pulse-jet baghouses.

(4) An appropriate methodology for monitoring cleaning cycles to ensure proper operation.

(5) Monthly check of bag cleaning mechanisms for proper functioning through visual inspection or equivalent means.

(6) Monthly check of bag tension on reverse air and shaker-type baghouses. Such checks are not required for shaker-type baghouses using self-tensioning (spring loaded) devices.

(7) Quarterly confirmation of the physical integrity of the baghouse through visual inspection of the baghouse interior for air leaks.

(8) Quarterly inspection of fans for wear, material buildup, and corrosion through visual inspection, vibration detectors, or equivalent means.

(9) Except as provided in paragraphs (g) and (h) of this section, continuous operation of a bag leak detection system, unless a system meeting the requirements of paragraph (m) of this section for a continuous emissions monitoring system is installed for monitoring the concentration of lead.

(d) The procedures you specify in the standard operating procedures manual for baghouse maintenance must include, at a minimum, a preventative maintenance schedule that is consistent with the baghouse manufacturer's instructions for routine and long-term maintenance.

(e) The bag leak detection system required by paragraph (c)(9) of this section, must meet the specification and requirements of paragraphs (e)(1) through (8) of this section.

(1) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 1.0 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(2) The bag leak detection system sensor must provide output of relative particulate matter loadings.

(3) The bag leak detection system must be equipped with an alarm system that will alarm when an increase in relative particulate loadings is detected over a preset level.

(4) You must install and operate the bag leak detection system in a manner consistent with the guidance provided in "Office of Air quality Planning and Standards (OAQPS) Fabric Filter Bag Leak Detection Guidance" EPA–454/R–98–015, September 1997 (incorporated by reference, see § 63.14) and the manufacturer's written specifications and recommendations for installation, operation, and adjustment of the system.

(5) The initial adjustment of the system must, at a minimum, consist of establishing the baseline output by adjusting the sensitivity (range) and the averaging period of the device, and establishing the alarm set points and the alarm delay time.

(6) Following initial adjustment, you must not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time, except as detailed in the approved standard operating procedures manual required under paragraph (a) of this section. You cannot increase the sensitivity by more than 100 percent or decrease the sensitivity by more than 50 percent over a 365 day period unless such adjustment follows a complete baghouse inspection that demonstrates that the baghouse is in good operating condition.

(7) For negative pressure, induced air baghouses, and positive pressure baghouses that are discharged to the atmosphere through a stack, you must install the bag leak detector downstream of the baghouse and upstream of any wet acid gas scrubber.

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

(f) You must include in the standard operating procedures manual required by paragraph (a) of this section a corrective action plan that specifies the procedures to be followed in the case of a bag leak detection system alarm. The corrective action plan must include, at a minimum, the procedures that you will use to determine and record the time and cause of the alarm as well as the corrective actions taken to minimize emissions as specified in paragraphs (f)(1) and (f)(2) of this section.

(1) The procedures used to determine the cause of the alarm must be initiated within 30 minutes of the alarm.

(2) The cause of the alarm must be alleviated by taking the necessary corrective action(s) that may include, but not be limited to, those listed in paragraphs (f)(2)(i) through (vi) of this section.

(i) Inspecting the baghouse for air leaks, torn or broken filter elements, or any other malfunction that may cause an increase in 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.

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

(g) Baghouses equipped with high efficiency particulate air (or HEPA) filters as a secondary filter used to control emissions from any source subject to the lead emission standards in § 65.543(a) or (b), are exempt from the requirement to be equipped with a bag leak detection system. You must monitor and record the pressure drop across each HEPA filter system daily. If the pressure drop is outside the limit(s) specified by the filter manufacturer, you must take appropriate corrective measures, which may include but not be limited to those given in paragraphs (g)(1) through (4) of this section.

(1) Inspecting the filter and filter housing for air leaks and torn or broken filters.

(2) Replacing defective filter media, or otherwise repairing the control device.

(3) Sealing off a defective control device by routing air to other control devices

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

(h) Baghouses followed by a wet electrostatic precipitator used as a secondary control device for any source subject to the lead emission standards in § 63.543(a) or (b), are exempt from the requirement to be equipped with a bag leak detection system.

(i) If you use a wet scrubber to control particulate matter and metal hazardous air pollutant emissions from a process vent to demonstrate continuous compliance with the emissions standards, you must monitor and record the pressure drop and water flow rate of the wet scrubber during the initial performance or compliance test conducted to demonstrate compliance with the lead emissions limit under § 63.543(a) or (b). Thereafter, you must monitor and record the pressure drop and water flow rate values at least once every hour and you must maintain the pressure drop and water flow rate at levels no lower than 30 percent below the pressure drop and water flow rate measured during the initial performance or compliance test.

(j) You must comply with the requirements specified in paragraphs (j)(1) through (4) of this section to demonstrate continuous compliance with the total hydrocarbons and dioxins and furans emissions standards. During periods of startup and shutdown, the requirements of paragraph (j)(4) of this section do not apply. Instead, you must demonstrate compliance with the standard for total hydrocarbon by meeting the requirements of § 63.543(l).

(1) Continuous temperature monitoring. You must install, calibrate, maintain, and continuously operate a device to monitor and record the temperature of the afterburner or furnace exhaust streams consistent with the requirements for continuous monitoring systems in § 63.8.

(2) Prior to or in conjunction with the initial performance or compliance test to determine compliance with § 63.543(c), you must conduct a performance evaluation for the temperature monitoring device according to § 63.8(e). The definitions, installation specifications, test procedures, and data reduction procedures for determining calibration drift, relative accuracy, and reporting described in Performance Specification 2, 40 CFR part 60, appendix B, sections 2, 3, 5, 7, 8, 9, and 10 must be used to conduct the evaluation. The temperature monitoring device must meet the following performance and equipment specifications:

(i) The recorder response range must include zero and 1.5 times the average temperature identified in paragraph (j)(3) of this section.

(ii) The monitoring system calibration drift must not exceed 2 percent of 1.5 times the average temperature identified in paragraph (j)(3) of this section.

(iii) The monitoring system relative accuracy must not exceed 20 percent.

(iv) The reference method must be a National Institute of Standards and Technology calibrated reference thermocouple-potentiometer system or an alternate reference, subject to the approval of the Administrator.

(3) You must monitor and record the temperature of the afterburner or the furnace exhaust streams every 15 minutes during the initial performance or compliance test for total hydrocarbons and dioxins and furans and determine an arithmetic average for the recorded temperature measurements.

(4) To demonstrate continuous compliance with the standards for total hydrocarbons and dioxins and furans, you must maintain an afterburner or exhaust temperature such that the average temperature in any 3-hour period does not fall more than 28 °Celsius (50 °Fahrenheit) below the average established in paragraph (j)(3) of this section.

(k) You must install, operate, and maintain a digital differential pressure monitoring system to continuously monitor each total enclosure as described in paragraphs (k)(1) through (5) of this section.

(1) You must install and maintain a minimum of one building digital differential pressure monitoring system at each of the following three walls in each total enclosure that has a total ground surface area of 10,000 square feet or more:

(i) The leeward wall.

(ii) The windward wall.

(iii) An exterior wall that connects the leeward and windward wall at a location defined by the intersection of a perpendicular line between a point on the connecting wall and a point on its furthest opposite exterior wall, and intersecting within plus or minus ten meters of the midpoint of a straight line between the two other monitors specified. The midpoint monitor must not be located on the same wall as either of the other two monitors.

(2) You must install and maintain a minimum of one building digital differential pressure monitoring system at the leeward wall of each total enclosure that has a total ground surface area of less than 10,000 square feet.

(3) The digital differential pressure monitoring systems must be certified by the manufacturer to be capable of measuring and displaying negative pressure in the range of 0.01 to 0.2 millimeters mercury (0.005 to 0.11 inches of water) with a minimum accuracy of plus or minus 0.001 millimeters of mercury (0.0005 inches of water).

(4) You must equip each digital differential pressure monitoring system with a continuous recorder.

(5) You must calibrate each digital differential pressure monitoring system in accordance with manufacturer's specifications at least once every 12 calendar months or more frequently if recommended by the manufacturer.

(l) Except as provided in paragraphs (l)(2) or (3) of this section, all new or reconstructed sources subject to the requirements under § 63.543 must install, calibrate, maintain, and operate a CEMS for measuring lead emissions. In addition to the General Provisions requirements for CEMS in § 63.8(c) that are referenced in Table 1 to this subpart, you must comply with the requirements for CEMS specified in paragraph (m) of this section.

(1) Sources subject to the emissions limits for lead compounds under § 63.543(b) must install a CEMS for measuring lead emissions within 180 days of promulgation by the EPA of performance specifications for lead CEMS.

(2) Prior to 180 days after the EPA promulgates performance specifications

for CEMS used to measure lead concentrations, you must use the procedure described in § 63.543(g)(1) to determine compliance.

(3) Vents from control devices that serve only to control emissions from buildings containing lead bearing materials are exempt from the requirement to install a CEMS for measuring lead emissions.

(m) If a CEMS is used to measure lead emissions, you must install a continuous emissions monitoring system with a sensor in a location that provides representative measurement of the exhaust gas flow rate at the sampling location of the CEMS used to measure lead emissions, taking into account the manufacturer's recommendations. The flow rate sensor is that portion of the system that senses the volumetric flow rate and generates an output proportional to that flow rate.

(1) The continuous emissions monitoring system must be designed to measure the exhaust gas flow rate over a range that extends from a value of at least 20 percent less than the lowest expected exhaust flow rate to a value of at least 20 percent greater than the highest expected exhaust gas flow rate.

(2) The continuous emissions monitoring system must be equipped with a data acquisition and recording system that is capable of recording values over the entire range specified in paragraph (m)(1) of this section.

(3) You must perform an initial relative accuracy test of the continuous emissions monitoring system in accordance with the applicable Performance Specification in appendix B to part 60 of this chapter.

(4) You must operate the continuous emissions monitoring system and record data during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments.

(5) If you have a CEMS to measure lead emissions, you must calculate the average lead concentration and flow rate monthly to determine compliance with § 63.543(a).

(6) When the continuous emissions monitoring system is unable to provide quality assured data, the following apply:

(i) When data are not available for periods of up to 48 hours, the highest recorded hourly emissions rate from the previous 24 hours must be used.

(ii) When data are not available for 48 or more hours, the maximum daily emissions rate based on the previous 30 days must be used.

§ 63.549 Notification requirements.

(a) You must comply with all of the notification requirements of § 63.9. Electronic notifications are encouraged if suitable for the specific case (*e.g.*, by electronic media such as Excel spreadsheet, on CD or hard copy), and when required by this subpart.

(b) You must submit the fugitive dust control standard operating procedures manual required under § 63.545(a) and the standard operating procedures manual for baghouses required under § 63.548(a) to the Administrator or delegated authority along with a notification that the smelter is seeking review and approval of these plans and procedures. You must submit this notification no later than January 7, 2013. For sources that commenced construction or reconstruction after January 5, 2012, you must submit this notification no later than 180 days before startup of the constructed or reconstructed secondary lead smelter, but no sooner than January 5, 2012. For an affected source that has received a construction permit from the Administrator or delegated authority on or before January 5, 2012, you must submit this notification no later than January 7, 2014.

§ 63.550 Recordkeeping and reporting requirements.

(a) You must comply with all of the recordkeeping and reporting requirements specified in § 63.10 that are referenced in Table 1 to this subpart.

(1) Records must be maintained in a form suitable and readily available for expeditious review, according to § 63.10(b)(1). However, electronic recordkeeping and reporting if suitable for the specific case (*e.g.*, by electronic media such as Excel spreadsheet, on CD or hard copy), and when required by this subpart.

(2) Records must be kept on site for at least 2 years after the date of occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

(b) The standard operating procedures manuals required in §§ 63.545(a) and 63.548(a) must be submitted to the Administrator in electronic format for review and approval of the initial submittal and whenever an update is made to the procedure.

(c) You must maintain for a period of 5 years, records of the information listed in paragraphs (c)(1) through (13) of this section.

(1) Electronic records of the bag leak detection system output.

(2) An identification of 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 corrective actions taken, and the date and time the cause of the alarm was corrected.

(3) All records of inspections and maintenance activities required under § 63.548(c) as part of the practices described in the standard operating procedures manual for baghouses required under § 63.548(a).

(4) Electronic records of the pressure drop and water flow rate values for wet scrubbers used to control metal hazardous air pollutant emissions from process fugitive sources as required in § 63.548(i).

(5) Electronic records of the output from the continuous temperature monitor required in § 63.548(j)(1), and an identification of periods when the 3-hour average temperature fell below the minimum established under § 63.548(j)(4), and an explanation of the corrective actions taken.

(6) Electronic records of the continuous pressure monitors for total enclosures required in § 63.548(k), and an identification of periods when the pressure was not maintained as required in § 63.544(c)(1).

(7) Records of any time periods power was lost to the continuous pressure monitors for total enclosures required in § 63.548(k) and records of loss of power to the air handling system maintaining negative pressure on total enclosures.

(8) Records of the inspections of facility enclosures required in § 63.544(d).

(9) Records of all cleaning and inspections required as part of the practices described in the standard operating procedures manual required under § 63.545(a) for the control of fugitive dust emissions.

(10) Electronic records of the output of any CEMS installed to monitor lead emissions meeting the requirements of § 63.548(m).

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

(12) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.543(k), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(13) Records of any periods of startup or shutdown of a furnace and actions taken to minimize emissions during that period in accordance with § 63.543(l).

(d) You must comply with all of the reporting requirements specified in § 63.10 of the General Provisions that are referenced in Table 1 to this subpart.

(1) You must submit reports no less frequent than specified under § 63.10(e)(3) of the General Provisions.

(2) Once a source reports a violation of the standard or excess emissions, you must follow the reporting format required under § 63.10(e)(3) until a request to reduce reporting frequency is approved by the Administrator.

(e) In addition to the information required under the applicable sections of § 63.10, you must include in the reports required under paragraph (d) of this section the information specified in paragraphs (e)(1) through (14) of this section.

(1) Records of the concentration of lead in each process vent, and records of the rolling 12-month flow-weighted average concentration of lead compounds in vent gases calculated monthly as required in § 63.543(a), except during the first year when the concentration is calculated using the method described in § 63.543(a)(2).

(2) Records of the concentration of total hydrocarbon and dioxins and furans in each process vent that has established limits for total hydrocarbon and dioxins and furans as required in § 63.543(c).

(3) Records of all periods when monitoring using a CEMS for lead or total hydrocarbon was not in compliance with applicable limits.

(4) Records of all alarms from the bag leak detection system specified in § 63.548.

(5) A description of the procedures taken following each bag leak detection system alarm pursuant to § 63.548(f)(1) and (2).

(6) A summary of the records maintained as part of the practices described in the standard operating procedures manual for baghouses required under § 63.548(a), including an explanation of the periods when the procedures were not followed and the corrective actions taken.

(7) An identification of the periods when the pressure drop and water flow rate of wet scrubbers used to control process fugitive sources dropped below the levels established in § 63.548(i), and an explanation of the corrective actions taken.

(8) Records of the temperature monitor output, in 3-hour block averages, for those periods when the temperature monitored pursuant to § 63.548(j) fell below the level established in § 63.548(j)(4).

(9) Certification that the plastic separation process for battery breakers required in § 63.543(m) was operated at all times the battery breaker was in service.

(10) Records of periods when the pressure was not maintained as required in § 63.544(c) or power was lost to the continuous pressure monitoring system as required in § 63.548(k).

(11) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction that occurred during the reporting period and caused or may have caused any applicable emissions limitation to be exceeded. The report must also include a description of actions taken during a malfunction of an affected source to minimize emissions in accordance with § 63.543(k), including actions taken to correct a malfunction.

(12) A summary of the fugitive dust control measures performed during the required reporting period, including an explanation of the periods when the procedures outlined in the standard operating procedures manual pursuant to § 63.545(a) were not followed and the corrective actions taken. The reports must not contain copies of the daily records required to demonstrate compliance with the requirements of the standard operating procedures manuals required under § 63.545(a).

(13) Records of any periods of startup or shutdown of a furnace including an explanation of the periods when the procedures required in § 63.543(l) were not followed and the corrective actions taken.

(14) You must submit records pursuant to paragraphs (e)(14)(i) through (iii) of this section.

(i) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*). Only data collected using test methods compatible with the Electronic Reporting Tool are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(ii) Within 60 days after the date of completing each CEMS performance evaluation test, as defined in § 63.2 and required by this subpart, you must submit the relative accuracy test audit data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool as mentioned in paragraph (e)(14)(i) of this section. Only data collected using test methods compatible with the Electronic Reporting Tool are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(iii) All reports required by this subpart not subject to the requirements in paragraph (e)(14)(i) and (ii) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.*, by electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (e)(14)(i) and (ii) of this section in paper format.

§ 63.551 Implementation and enforcement.

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or tribal agency.

(c) The authorities that cannot be delegated to State, local, or tribal agencies are as specified in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the requirements in §§ 63.541, 63.543 through 63.544, § 63.545, and § 63.546.

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f), as defined in § 63.90, and as required in this subpart.

(3) Approval of major alternatives to monitoring under § 63.8(f), as defined in § 63.90, and as required in this subpart.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f), as defined in § 63.90, and as required in this subpart.

§ 63.552 Affirmative defense to civil penalties for exceedance of emissions limit during malfunction.

In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

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

(1) The excess emissions:

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

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

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

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance.

(2) Repairs were made as expeditiously as possible when the applicable emissions limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs.

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions.

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

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

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

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs.

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

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

(b) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emissions limit(s) during a malfunction, shall notify the Administrator by telephone or facsimile transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense, shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45-day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

TABLE 1 TO SUBPART X OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART X

Reference	Applies to subpart X	Comment
63.1	Yes.	
63.2	Yes.	
63.3	Yes.	
63.4	Yes.	
63.5	Yes.	
63.6(a), (b), (c)	Yes.	
63.6(d)	No.	Section reserved.
63.6(e)(1)(i)	No.	See 63.543(k) for general duty requirement.
63.6(e)(1)(ii)	No.	
63.6(e)(1)(iii)	Yes.	
63.6(e)(2)	No.	Section reserved.
63.6(e)(3)	No.	
63.6(f)(1)	No.	
63.6(g)	Yes.	
63.6(h)	No.	No opacity limits in rule.
63.6(i)	Yes.	
63.6(j)	Yes.	
63.7(a)–(d)	Yes.	
63.7(e)(1)	No.	See 63.543(j).
63.7(e)(2)–(e)(4)	Yes.	
63.7(f), (g), (h)	Yes.	
63.8(a)–(b)	Yes.	
63.8(c)(1)(i)	No.	See 63.543(k) for general duty requirement.

TABLE 1 TO SUBPART X OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART X—Continued

Reference	Applies to subpart X	Comment
63.8(c)(1)(ii)	Yes.	
63.8(c)(1)(iii)	No.	
63.8(c)(2)–(d)(2)	Yes.	
63.8(d)(3)	Yes, except for last sentence.	
63.8(e)–(g)	Yes.	
63.9(a), (b), (c), (e), (g), (h)(1)through (3), (h)(5) and (6), (i) and (j).	Yes.	
63.9(f)	No.	
63.9(h)(4)	No.	Reserved.
63.10 (a)	Yes.	
63.10 (b)(1)	Yes.	
63.10(b)(2)(i)	No.	
63.10(b)(2)(ii)	No.	See 63.550 for recordkeeping of occurrence and duration of malfunctions and recordkeeping of actions taken during malfunction.
63.10(b)(2)(iii)	Yes.	
63.10(b)(2)(iv)–(b)(2)(v)	No.	
63.10(b)(2)(vi)–(b)(2)(xiv)	Yes.	
63.(10)(b)(3)	Yes.	
63.10(c)(1)–(9)	Yes.	
63.10(c)(10)–(11)	No.	See 63.550 for recordkeeping of malfunctions.
63.10(c)(12)–(c)(14)	Yes.	
63.10(c)(15)	No.	
63.10(d)(1)–(4)	Yes.	
63.10(d)(5)	No.	See 63.550(e)(11) for reporting of malfunctions.
63.10(e)–(f)	Yes.	
63.11	No.	Flares will not be used to comply with the emission limits.
63.12 to 63.15	Yes.	

TABLE 2 TO SUBPART X OF PART 63—EMISSIONS LIMITS FOR SECONDARY LEAD SMELTING FURNACES

For vents from these processes . . .	You must meet the following emissions limits . . . [a]	
	Total hydrocarbon ppm by volume expressed as propane corrected to 4 percent carbon dioxide	Dioxin and furan (dioxins and furans) nanograms/dscm expressed as TEQ corrected to 7 percent O_2
Collocated blast and reverberatory furnaces (new and existing)	20 ppmv	0.50 ng/dscm.
Collocated blast and reverberatory furnaces when the reverberatory furnace is not operating for units that comments construction or reconstruction before June 9, 1994.	360 ppmv	170 ng/dscm.
Collocated blast and reverberatory furnaces when the reverberatory furnace is not operating for units that commence construction or reconstruction after June 9, 1994.	70 ppmv	170 ng/dscm.
Blast furnaces that commence construction or reconstruction before June 9, 1994.	360 ppmv	170 ng/dscm.
Blast furnaces that commence construction or reconstruction after June 9, 1994.	70 ppmv	170 ng/dscm.
Blast furnaces that commence construction or reconstruction after May 19, 2011.	70 ppmv	10 ng/dscm.
Reverberatory and electric furnaces that commence construction or reconstruction before May 19, 2011.	12 ppmv	0.20 ng/dscm.
Reverberatory and electric furnaces that commence construction or reconstruction after May 19, 2011.	12 ppmv	0.10 ng/dscm.

[a] There are no standards for dioxins and furans during periods of startup and shutdown.

TABLE 3 TO SUBPART X OF PART 63—TOXIC EQUIVALENCY FACTORS

Dioxin/furan congener	Toxic equivalency factor
2,3,7,8-tetrachlorinated dibenzo-p-dioxin	1
1,2,3,7,8-pentachlorinated dibenzo-p-dioxin	0.5
1,2,3,4,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzo-p-dioxin	0.01
octachlorinated dibenzo-p-dioxin	0.001

TABLE 3 TO SUBPART X OF PART 63—TOXIC EQUIVALENCY FACTORS—Continued

Dioxin/furan congener	Toxic equivalency factor
2,3,7,8-tetrachlorinated dibenzofuran	0.1
2,3,4,7,8-pentachlorinated dibenzofuran	0.05
1,2,3,7,8-pentachlorinated dibenzofuran	0.5
1,2,3,4,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,7,8,9-hexachlorinated dibenzofuran	0.1

[FR Doc. 2011–32933 Filed 1–4–12; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2010–0786; FRL–9491–4]

RIN 2060–AQ42

National Emission Standards for Hazardous Air Pollutant Emissions for Shipbuilding and Ship Repair (Surface Coating); National Emission Standards for Wood Furniture Manufacturing Operations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes the residual risk and technology review conducted for two industrial source categories regulated by separate national emission standards for hazardous air pollutants. The two national emission standards for hazardous air pollutants are: National Emissions Standards for Shipbuilding and Ship Repair (Surface Coating) and National Emissions Standards for Wood Furniture Manufacturing Operations. This action also finalizes revisions to the regulatory provisions related to emissions during periods of startup, shutdown and malfunction.

DATES: This final action is effective on November 21, 2011.

ADDRESSES: The EPA has established a docket for this action under Docket ID Number EPA–HQ–OAR–2010–0786. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet, and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA Docket Center, EPA West Building, Room Number 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time, Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744 and the telephone number for the Air and Radiation Docket and Information Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action regarding the Wood Furniture Manufacturing Operations National Emission Standards for Hazardous Air Pollutants (NESHAP), contact Mr. Nicholas Swanson, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Natural Resources Group (E143–03), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–4080; fax number: (919) 685–3219; and email address: *swanson.nicholas@epa.gov*. For questions about this final action regarding the Shipbuilding and Ship Repair (Surface Coating) NESHAP, contact Ms. Tina Ndoh, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Minerals and Manufacturing Group (E243–04), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–2750; fax number: (919) 685–5450; and email address: *ndoh.tina@epa.gov*.

SUPPLEMENTARY INFORMATION: For specific information regarding the modeling methodology, contact Mr. James Hirtz, Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Toxics Assessment Group (C539–02), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–0881; fax number: (919) 541–0840; and email address: *hirtz.james@epa.gov*. For information about the applicability of these two NESHAP to a particular entity, contact Dr. Rafael Sanchez, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, Washington, DC 20460; telephone number: (202) 564–7028; fax number: (202) 564–0050; and email address: *sanchez.rafael@epa.gov*.

Background Information Document. On December 21, 2010 (75 FR 80220), the EPA proposed revisions to the Shipbuilding and Ship Repair (Surface Coating) NESHAP and the Wood Furniture Manufacturing Operations NESHAP, which were evaluated in our residual risk and technology review (RTR). A summary of the public comments on the proposal and the EPA's responses to the comments is available in Docket ID Number EPA–HQ–OAR–2010–0786.

Organization of this Document. The following outline is provided to aid in locating information in the preamble.

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D. What are the effective and compliance dates of the standards?
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VII. Statutory and Executive Order Reviews
A. Executive Orders 12866: Regulatory Planning and Review, and Executive Order 13563: Improving Regulation and Regulatory Review
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D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use
I. National Technology Transfer and Advancement Act (NTTAA)
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act (CRA)

I. General Information

A. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action include:

NESHAP and source category	NAICS [1] Code
Shipbuilding and Ship Repair (Surface Coating)	336611.
Wood Furniture Manufacturing Operations	3371, 3372, 3379.

[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 affected by the final action for the source categories listed. To determine whether your facility would be affected, you should examine the applicability criteria in the appropriate NESHAP. If you have any questions regarding the applicability of either of these NESHAP, please contact the appropriate 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 will also be available on the World Wide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the final action will be posted on the TTN's policy and guidance page for newly proposed and promulgated rules at the following address: *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html*. The TTN provides information and technology exchange in various areas of air pollution control.

Additionally, information on the source category descriptions, detailed emissions and other data that were used as inputs to the risk assessments can be found at this site.

C. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the Court) by January 20, 2012. Under section 307(b)(2) of the CAA, the requirements established by these final rules may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background

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

For MACT standards, the statute specifies certain minimum stringency requirements, which are referred to as floor requirements, and may not be based on cost considerations. See CAA section 112(d)(3). For new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best controlled similar source. The MACT standards for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT, we must also consider control options that are more stringent than the floor under CAA section 112(d)(2). We may establish standards more stringent than the floor, based on the consideration of the cost of achieving the emissions reductions, any nonair quality health and environmental impacts and energy requirements. In promulgating MACT standards, CAA section 112(d)(2) directs us to consider the application of measures, processes, methods, systems or techniques that reduce the volume of or eliminate HAP emissions through process changes, substitution of materials or other modifications; enclose systems or processes to eliminate emissions; collect, capture or treat HAP when released from a process, stack, storage or fugitive emissions point; and/or are design, equipment, work practice or operational standards.

In the second stage of the regulatory process, we undertake two different analyses, as required by the CAA. Section 112(d)(6) of the CAA calls for us to review the technology-based standards and to revise them "as necessary (taking into account developments in practices, processes, and control technologies)" no less frequently than every 8 years. Within 8 years after promulgation of the technology standards, CAA section 112(f) calls for us to evaluate the risk to public health remaining after application of the technology-based standards and to revise the standards, if necessary, to provide an ample margin of safety to protect public health or to prevent, taking into consideration costs, energy, safety and other relevant factors, an adverse environmental effect. In doing so, the EPA may adopt standards equal to existing MACT standards if the EPA determines that the existing standards are sufficiently protective. National Resources Defense Council (*NRDC*) v. *EPA*, 529 F.3d 1077, 1083 (DC Cir. 2008).

On December 21, 2010, the EPA published a proposed rule in the **Federal Register** for these two NESHAP that took into consideration the residual risk and technology review (RTR) analyses. For these NESHAP—Shipbuilding and Ship Repair (Surface Coating) and Wood Furniture

Manufacturing Operations—this action provides the EPA's final determinations and regulatory amendments pursuant to the RTR provisions of CAA section 112. For both NESHAP, we also are finalizing revisions to requirements in each NESHAP related to emissions during periods of startup, shutdown and malfunction (SSM). This action also addresses formaldehyde limits and the use of conventional spray technology for the Wood Furniture Manufacturing Operations NESHAP.

III. Summary of the Final Rules

A. What are the final rule amendments for the Shipbuilding and Ship Repair (Surface Coating) source category?

The NESHAP for Shipbuilding and Ship Repair (Surface Coating) were promulgated on December 15, 1995 (60 FR 64330), and codified at 40 CFR part 63, subpart II. The shipbuilding and ship repair industry consists of establishments that build, repair, repaint, convert and alter ships which are marine or fresh-water vessels used for military or commercial operations. The source category covered by this MACT standard includes only the shipbuilding and ship repair surface coating operations that occur at facilities that are major sources of HAP.

We are finalizing the Shipbuilding and Ship Repair (Surface Coating) rule as it was proposed, with no changes. For the reasons provided in the proposed rule and in the support documents in the docket, we have determined that the current MACT standards for shipbuilding and ship repair (surface coating) facilities reduce risk to an acceptable level, provide an ample margin of safety to protect public health and prevent an adverse environmental effect. We are, therefore, re-adopting the existing MACT standards to satisfy section 112(f) of the CAA. We have determined that the developments in technology would give minimal health benefits and are not cost effective. The costs of implementing developments in practices, processes or control technologies since promulgation of the MACT standards are disproportionate to the emission reduction that would be achieved and, therefore, we are not adopting additional technology standards pursuant to CAA section 112(d)(6).

We are finalizing changes to the Shipbuilding and Ship Repair (Surface Coating) MACT standards to eliminate the SSM malfunction exemption. These changes revise Table 1 in 40 CFR part 63, subpart II, to indicate that several requirements of the 40 CFR part 63 General Provisions related to periods of SSM do not apply. We are adding provisions to the Shipbuilding and Ship Repair (Surface Coating) MACT standards requiring sources to operate in a manner that minimizes emissions, removing the SSM plan requirement, clarifying the required conditions for performance tests and revising the SSM-associated recordkeeping and reporting requirements to require reporting and recordkeeping for periods of malfunction. It is required that all facilities comply with the NESHAP during startup and shutdown. We are also finalizing provisions, generally as proposed, to provide an affirmative defense against civil penalties for potential violations of emission standards caused by malfunctions, as well as criteria for establishing the affirmative defense.

These revisions to the Shipbuilding and Ship Repair (Surface Coating) MACT standards are not expected to result in any emissions reduction or economic impacts. We have determined that facilities in this source category can meet the applicable emissions standards at all times. No changes in costs to industry are predicted.

B. What are the final rule amendments for the Wood Furniture Manufacturing Operations source category?

The NESHAP for Wood Furniture Manufacturing Operations were promulgated on December 7, 1995 (60 FR 62930), and codified at 40 CFR part 63, subpart JJ. The Wood Furniture Manufacturing Operations source category consists of establishments that produce a range of wood products, including wood kitchen cabinets, wood residential furniture, upholstered residential and office furniture, wood office furniture and fixtures, partitions, shelving, lockers and other wood furniture not included in one of the categories listed above. The source category covered by this MACT standard includes only the wood furniture manufacturing operations that occur at facilities that are major sources of HAP.

In the proposal for this rule making, the EPA proposed a formaldehyde emissions limit of 400 pounds per 12-month period. As discussed in section IV.B.1 below, the EPA received comments concerning potential impacts on facilities with high production volume and determined that the proposed limit would not be cost effective for all facilities in the source category. For this reason, the EPA is finalizing two alternative compliance options. Under the authority of section 112(d)(6) of the CAA, we are finalizing a limit on formaldehyde emissions by limiting formaldehyde content in coatings and contact coatings and contact adhesives to 1 percent by weight. As an alternative compliance option, we are allowing facilities to comply with a formaldehyde usage limit of 400 pounds per rolling 12-month period, as we originally proposed. Less than 20 facilities are known to exceed 400 pounds per 12-month period based on 2005 National Emissions Inventory (NEI) data and communications with wood furniture manufacturing facilities.[1] The phone calls indicated that there were reductions in emissions since the 2005 NEI and all but one of the facilities contacted were below 400 pounds per 12-month period. This leads us to conclude that most of the facilities that exceeded 400 pounds of formaldehyde per 12 month period according to the 2005 NEI are now below that level. We are aware of at least one facility that has facilities with high production volume that still exceeds the 400 pound level. After receiving updated information, we concluded that the proposed 400 pounds formaldehyde per rolling 12-month period usage limit was not cost effective as a mandatory formaldehyde limit for all facilities within the source category. For this reason, the EPA is adopting the 400 pound formaldehyde limit as an alternative requirement to the requirement to limit formaldehyde content to 1 percent in coatings and contact adhesives. The 400 pound limit would not be cost effective for facilities with high production volume because, while they use low-formaldehyde coatings, these facilities would still exceed the 400 pounds per 12-month period because of the quantity of coatings and contact adhesives applied. To further reduce formaldehyde emissions, these facilities would require the addition of costly control devices and/or reconstruction of their spray line system. For more information, see *Estimated Cost Impact for Wood Furniture Manufacturing Industry To Comply With Proposed Formaldehyde Limit on Coating Operations Wood Furniture Manufacturing RTR*, dated August 4, 2011, in the docket for this action. Such facilities can, however, cost-effectively comply with a standard

[1] The memo to the docket, *Impacts of Implementing a Limit on Formaldehyde Usage in the Wood Furniture Manufacturing Operations Source Category*, dated October 19, 2010, shows that there are 27 facilities that exceed 400 pounds per year of formaldehyde emissions according to 2005 NEI data. Calls to industry showed that many of these facilities have lowered their emissions of formaldehyde significantly since 2005 as shown in the memo *Updated Formaldehyde Emissions from Select Wood Furniture Manufacturers*, dated August 3, 2011, in the docket for this action.

that limits the formaldehyde content of coatings and contact adhesives to 1 percent.[2] While the formaldehyde content of coating and contact adhesive formulations have been reduced since promulgation of the 1995 NESHAP, the EPA has received information that some facilities may still rely on formulations that contain greater than 1 percent formaldehyde.[3] The EPA has determined that some of these facilities could not readily meet the 1 percent formaldehyde limit and so is allowing, as an alternative compliance option, the originally proposed 400 pound formaldehyde limit.

We are also finalizing, with one modification, the proposed prohibition on the use of conventional spray[4] guns pursuant to CAA section 112(d)(6). As explained in the proposed rule and supporting documents in the docket, we have determined that use of non-conventional spray guns results in lower HAP emissions than use of conventional spray guns. When spraying a piece of wood furniture with a coating, there is a prescribed amount of coating to be applied to the wood surface. With the higher spray efficiency associated with non-conventional spray guns, less spray is generally required to apply the desired amount of coating so less coating is used. This means that less overspray will occur, creating fewer emissions. Conventional spray guns are now used infrequently in the wood furniture manufacturing industry, and the costs to use non-conventional spray guns are approximately equal to conventional spray guns. The EPA estimates that the switch to non-conventional spray guns does not incur a cost burden associated with decreased product consumption and cost.[5]

Considering information received during the comment period that some facilities route conventional spray gun overspray to control devices, we are modifying the proposed prohibition on the use of conventional spray guns to retain an exception in the NESHAP to allow the use of conventional spray guns if emissions from the finishing station are routed to a control device. See 40 CFR 63.803(h)(4). The efficiency of the control device, even when coupled with the conventional spray gun, reduces excess emissions better than a change to high efficiency spray technology. The EPA does not expect facilities will incur the significant cost of installing a control device for the sole purpose of using conventional spray guns. We expect the vast majority of facilities to use non-conventional applicators of wood furniture finishes, with only a small number of facilities choosing to use conventional spray guns with a control device.

We are also finalizing changes to the Wood Furniture Manufacturing Operations NESHAP to eliminate the SSM exemption. These changes revise Table 1 in 40 CFR part 63, subpart JJ, to indicate that several requirements of the 40 CFR part 63 General Provisions related to periods of SSM do not apply. We are adding provisions to the Wood Furniture Manufacturing Operations MACT standards requiring sources to operate in a manner that minimizes emissions, removing the SSM plan requirement, clarifying the required conditions for performance tests and revising the SSM-associated recordkeeping and reporting requirements to require reporting and recordkeeping for periods of malfunction. We are also adding provisions to provide an affirmative defense against civil penalties for exceedances of emission standards caused by malfunctions, as well as criteria for establishing the affirmative defense.

We are finalizing language to clarify the applicability for Wood Furniture Manufacturing Operations to be consistent with surface coating rules issued after the promulgation of the Wood Furniture MACT standards in 1995. These include the subparts for Surface of Miscellaneous Metal Parts and Products (MMMM), Surface Coating of Plastic Parts and Products (PPPP), Surface Coating of Wood Building Products (QQQQ), and Surface Coating of Metal Furniture (RRRR) of 40 CFR part 63. Subparts MMMM, PPPP, QQQQ and RRRR exempt surface coating operations that are subject to other subparts of 40 CFR part 63, such as the Wood Furniture Operations MACT standards. (See 40 CFR 63.3881(c)(6), 63.4481(c)(7), 63.4681(c)(2), 63.4881(c)(2)). Therefore, we are finalizing amendments to the Wood Furniture Operations MACT standards to acknowledge that surface coating operations that are subject to subparts MMMM, PPPP, QQQQ or RRRR of 40 CFR part 63 are not subject to the Wood Furniture Manufacturing Operations standards.

In this action, we are taking a step to improve data accessibility. Owners and operators demonstrating compliance using the test methods cited in § 63.805(c), as an alternative to § 63.9(h), are not required but may submit electronic copies of required performance test reports through the Electronic Reporting Tool (ERT). The ERT transmits the electronic report through EPA's Central Data Exchange network for storage in the WebFIRE database making submittal of data very straightforward and easy. The WebFIRE database was constructed to store performance test data for use in developing emission factors. A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/ert_tool.html*. A description of the WebFIRE database is available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main*.

The ERT would allow for an electronic review process rather than a manual data assessment, making review and evaluation of the source-provided data and calculations easier and more efficient. Finally, having data submitted electronically, the EPA would be able to develop improved emission factors, make fewer information requests and promulgate better regulations. These revisions to the Wood Furniture Manufacturing Operations MACT standards are not expected to result in economic or quantifiable environmental impacts. We have determined that facilities in this source category can meet the applicable emissions standards at all times.

C. What are the requirements during periods of startup, shutdown and malfunction?

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

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[2] The concentrations of formaldehyde received from the known facility with high production volume exceeds 400 pounds per 12-month period is in the *Estimated Cost Impact for Wood Furniture Manufacturing Industry To Comply With Proposed Formaldehyde Limit on Coating Operations Wood Furniture Manufacturing RTR*, dated August 4, 2011, in the docket for this action.

[3] For more details, see *Conversation with a Representative of Kitchen Cabinet Manufacturers Association (KCMA) Regarding Add-On Control Devices and High Formaldehyde Concentration in Coatings*, dated June 23, 2011, in the docket for this action.

[4] The definition of "conventional spray" can be found in the 1995 Wood Furniture Manufacturing Operations NESHAP.

[5] See *Developments in Practices, Processes, and Control Technologies*, dated August 24, 2010 in the docket for this action.

While the Court's ruling in *Sierra Club* v. *EPA*, 551 F.3d 1019 (DC Cir. 2008), did not directly affect the two NESHAP addressed here, the legality of source category-specific SSM provisions, such as those in both NESHAP, are called into question based on the reasoning in that decision.

Consistent with *Sierra Club* v. *EPA*, we have eliminated the SSM exemptions in these two NESHAP. We have also revised Table 1 (the General Provisions table) for subparts II and JJ in several respects. For example, we have eliminated the incorporation of the General Provisions' requirement that the source develop an SSM plan. We have also eliminated or revised certain recordkeeping and reporting requirements that related to the SSM exemption. The EPA has attempted to ensure that we have removed any provisions that are inappropriate, unnecessary or redundant in the absence of the SSM exemption in the regulatory language.

The EPA has not established different standards for periods of startup and shutdown for these NESHAP because we believe compliance with the standards is achievable during these periods. For facilities that comply with the NESHAP by using compliant coatings and contact adhesives, there are no startup or shutdown events that would cause emissions that are different than those that occur during normal operations. For facilities that use control devices, there is sufficient ability for the control device to be started prior to the spray lines being started and conversely shutdown after the spray lines have shutdown. In the example of a regenerative thermal oxidizer (RTO), supplemental fuel can be provided during startup and shutdown of the spray lines to prevent noncompliance. Thus, we are not aware of any technical limitations such that emissions from startup or shutdown cannot be controlled by control devices to the level achieved during normal operations.

Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. * * *" (40 CFR 63.2). The EPA has determined that CAA section 112 does not require emissions that occur during periods of malfunction to be factored into development of CAA section 112 standards. Under section 112, emissions standards for new sources must be no less stringent than the level "achieved" by the best controlled similar source, and for existing sources, generally must be no less stringent than the average emission limitation "achieved" by the best performing 12 percent of sources in the category. There is nothing in section 112 that directs the agency to consider malfunctions in determining the level "achieved" by the best performing or best controlled sources when setting emission standards. Moreover, while the EPA accounts for variability in setting emissions standards consistent with section 112 case law, nothing in that case law requires the agency to consider malfunctions as part of that analysis. Section 112 uses the concept of "best controlled" and "best performing" unit in defining the level of stringency that section 112 performance standards must meet. Applying the concept of "best controlled" or "best performing" to a unit that is malfunctioning presents significant difficulties, as malfunctions are sudden and unexpected events.

Further, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category, and given the difficulties associated with predicting or accounting for the frequency, degree and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not "reasonably" foreseeable. See, *e.g.*, *Sierra Club* v. *EPA*, 167 F. 3d 658, 662 (D.C. Cir. 1999) (The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to "invest the resources to conduct the perfect study"). See also, *Weyerhaeuser* v. *Costle*, 590 F.2d 1011, 1058 (D.C. Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation."). In addition, the goal of a best controlled or best performing source is to operate in such a way as to avoid malfunctions of the source, and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with section 112 and is a reasonable interpretation of the statute.

In the event that a source fails to comply with the applicable CAA section 112 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112 standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail, and that such failure can sometimes cause an exceedance of the relevant emission standard. (See, *e.g.*, *State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown* (Sept. 20, 1999); *Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions* (Feb. 15, 1983)). The EPA is, therefore, adding to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. See 40 CFR 63.782 (Shipbuilding and Ship Repair (Surface Coating)) and 63.801 (Wood Furniture Manufacturing Operations) (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also have added other regulatory provisions to specify the elements that are necessary to establish this affirmative defense. See 40 CFR 63.781 (Shipbuilding and Ship Repair (Surface Coating)) and 63.800 (Wood Furniture Manufacturing Operations). The source must prove by a preponderance of the evidence that it has met all of the elements set forth in the affirmative defense. See also 40 CFR 22.24. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonably

preventable and not caused by poor maintenance and/or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner. * * *" The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.783(b)(1) and 63.802(c) and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *" In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense, and, if the respondent has not met its burden of proving compliance with all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR 22.27).

The EPA included an affirmative defense in the final rule in an attempt to balance a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that "limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis." 42 U.S.C. 7602(k)(defining "emission limitation and emission standard"). *See generally Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (D.C. Cir. 2008). Thus, the EPA is required to ensure that section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief. While "continuous" limitations, on the one hand, are required, there is also case law indicating that in many situations, it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), the DC Circuit acknowledged that in setting standards under CAA section 111 "variant provisions" such as provisions allowing for upsets during startup, shutdown and equipment malfunction "appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force." See also, *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973). Though intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments undermine the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating "upsets beyond the control of the permit holder." *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). *But see, Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission limitations are "continuous" as required by 42 U.S.C. 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

D. What are the effective and compliance dates of the standards?

The revisions to the MACT standards being promulgated in this action are effective on November 21, 2011. For the two MACT standards addressed in this action, the compliance date for the revised SSM-related requirements is November 21, 2011. For the Wood Furniture Manufacturing Operations NESHAP, the compliance date for the 1 percent formaldehyde coating and contact adhesive limit and the alternative 400 pound per 12-month formaldehyde use limit as well as the prohibition on the use of conventional spray guns is 3 years from the effective date of the standards, November 21, 2014. Beyond the revised SSM provisions, there are no changes to the Shipbuilding and Ship Repair (Surface Coating) NESHAP.

IV. Summary of Significant Changes Since Proposal

A. What changes did we make to the Shipbuilding and Ship Repair (Surface Coating) NESHAP since proposal?

Following the proposed notice of the RTR for Shipbuilding and Ship Repair (Surface Coating), the EPA did not receive any new data demonstrating any cost effective technology updates or data that would affect our analyses of risks. Accordingly, we have made no changes to the proposed rule language for the Shipbuilding and Ship Repair (Surface Coating) NESHAP. However, we corrected an inadvertent error made in the preamble to the proposed rule. In describing the Shipbuilding and Ship Repair (Surface Coating) source category, we incorrectly stated that there were approximately 85 facilities subject to the Shipbuilding and Ship Repair (Surface Coating) MACT, and that 71 of these 85 facilities, or approximately 84 percent of the source category, were modeled for the risk analysis. At proposal, we actually estimated that there were 90 facilities subject to the MACT, and of those 90 facilities, we modeled approximately 94 percent, or 85 facilities, in the risk analysis. This correction to the preamble text does not affect the estimated risks or any conclusions of the risk review. This correction only affects the inadvertent error made in the preamble text for the proposed rule.

B. What changes did we make to the Wood Furniture Manufacturing Operations NESHAP since proposal?

1. Formaldehyde Limit

The potential risk reductions associated with advancement in coating and adhesive formulations, described below, led us to propose a formaldehyde limit of 400 pounds per rolling 12-month period, in part because we believed that this limit could be achieved cost-effectively. We stated in the proposal that there are many coatings and adhesives available that contain no or low quantities of formaldehyde, and we expected any facilities above the 400 pounds per 12 month limit to be able to reduce their emissions below the 400 pound level by using coatings and adhesives with no or low formaldehyde. We proposed the formaldehyde usage limit under the authority of CAA section 112(f) and solicited comment on whether the proposed limit on formaldehyde use should be issued under CAA section 112(d)(6).

Comments received after proposal led the EPA to conduct further analyses of

the compliance costs associated with the proposed 400 pound usage limit. Data received from one facility, which already uses no- and low-formaldehyde content coatings and contact adhesives, indicated that reduction in formaldehyde use to 400 pounds per 12-month period would not be possible by simply using no- and low-formaldehyde content coatings and contact adhesives due to the size of its operations and the amount of coatings and contact adhesives used. To comply with the proposed 400 pound limit, a spray line reconfiguration (adding five drying/curing ovens) would be needed. The cost-effectiveness of formaldehyde reduction for the spray line reconfiguration was estimated to be $658,000/ton of formaldehyde reduced annually. We believe other large operation facilities would face similar circumstances. The EPA does not have specific information on compliance costs for facilities other than Kitchen Kompact, but even if we assume all other wood furniture facilities with formaldehyde emissions above 400 pounds per 12-month period in the 2005 NEI database would reduce their formaldehyde emissions to 400 pound per 12-month period and would incur zero costs in doing so, the cost-effectiveness would be $43,000/ton of formaldehyde reduced. We conclude this is not cost effective.[6]

Since the MACT was promulgated, manufacturers of coatings and contact adhesives have been able to replace formaldehyde with less toxic chemicals, resulting in products that are known in the industry as "low-formaldehyde" or "no-formaldehyde." This development is particularly evident in the reformulation of conversion varnishes used in kitchen cabinet manufacturing (see *Conversation with Valspar Regarding Formaldehyde Replacement Chemicals in Coatings,* dated August 4, 2011, in the docket for this action).The EPA's proposed 400 pound limit was based on the availability of low-formaldehyde coatings and contact adhesives and their use as the current state of technology. Although there is no formal industry definition of the term "low-formaldehyde," the EPA found that a formaldehyde content equal to or less than 1 percent by weight currently is consistent with the industry trend of continually reducing low formaldehyde formulations. We are aware of a range of values used in the industry to indicate "low-formaldehyde" (from 0.1 percent to 1.0 percent). Based on information available to the EPA, we determined that a formaldehyde content level of 1 percent is the lowest concentration that is clearly cost effective for the entire source category. We are, therefore, finalizing a limit of 1 percent formaldehyde by weight based on the availability of coatings and technical specifications necessary to maintain product quality and cost-effectiveness.[7] A content less than 1 percent would not allow facilities the flexibility to use coatings and adhesives that are suitable for a range of different products, from cabinets to home furnishings, without compromising their quality, cost or production.[8] Also, in many cases, the 1 percent formaldehyde content limit will allow flexibility in different types of line configurations.[9]

The proposed formaldehyde limit (400 pounds per rolling 12-month period) under CAA section 112(f) was based on these grounds—that wood furniture manufacturers can and are reducing their formaldehyde emissions through the use of newer low-formaldehyde coating and contact adhesive formulations (see 75 FR 80246). The limit of 1 percent formaldehyde in coatings and contact adhesives in this final rulemaking is an outgrowth of what the expected means of compliance was during the proposal for the proposed 400 pound limit. The EPA has confirmed that most facilities are using low- and no-formaldehyde coatings and contact adhesives (i.e., coatings and adhesives that have a formaldehyde concentration not exceeding 1 percent by weight).[10] Facilities can thus achieve formaldehyde emissions reductions that are greater than those required under the existing MACT standard. The original Wood Furniture Manufacturing Operations NESHAP achieved an 89 percent reduction in HAP. The industry, for the most part, has gone beyond the original NESHAP for formaldehyde emissions by continuing to use lower concentrations of formaldehyde in the coatings and contact adhesives. By codifying these practices, the EPA is setting a more stringent standard than was adopted in 1995 and will prevent backsliding into techniques and formulations used in the past.

CAA section 112(d)(6) requires us to revise emissions standards taking into account developments in practices, processes and control technologies. Thus, to codify current industry practice since the MACT was promulgated and to prevent potential increases in formaldehyde emissions in the future from coating and contact adhesive use in the wood furniture manufacturing industry, we are finalizing, under section 112(d)(6) of the CAA, formaldehyde emissions limits through two compliance options. One option is for new and existing sources to use only those coatings and contact adhesives with a formaldehyde content of 1 percent by weight or less. As these low-formaldehyde coatings are readily available in the marketplace and are comparable in cost to other coating and contact adhesive formulations, we expect no additional costs associated with the use of low-formaldehyde coatings and contact adhesives.

Moreover, we are retaining the proposed standard—a limit on the use of formaldehyde of 400 pounds per rolling 12-month period—as an alternative emission limit to the 1 percent formaldehyde formulation limit. While the EPA recognizes it is not cost effective for at least one facility to achieve a limit on the use of formaldehyde of 400 pounds per 12 month period, we acknowledge that most wood furniture manufacturing facilities' formaldehyde use is already below this limit.[11] It is likely that a small subset of low-emitting niche facilities use higher concentration formaldehyde coatings that may prefer

[6] For more information regarding cost estimates for compliance with the proposed 400 pound per year formaldehyde limit, refer to *Estimated Cost Impact for Wood Furniture Manufacturing Industry to Comply with Proposed Formaldehyde Limit on Coating Operations Wood Furniture Manufacturing RTR,* dated August 4, 2011.

[7] Discussion with a coatings manufacturer revealed that the label of "Low-Formaldehyde" is subjective and it trends towards lower and lower concentrations of formaldehyde. For more details, see *Telephone Call with Valspar Regulatory Affairs Manager—Wood Coatings Wood Furniture Manufacturing RTR* dated June 29, 2011 in the docket for this action. Also as noted previously, Valspar does not carry any products that exceed 1 percent in formaldehyde concentration.

[8] It is necessary for some facilities to minimize levels of formaldehyde in the coating formulation to promote cross-linking nucleation. This process directly affects the quality and durability of the wood furniture. See notes from the *Marsh Furniture Site Visit* in the docket for this action for reference.

[9] For additional information, please see memo to the docket, *EPA Meeting with Kitchen Cabinet Manufacturers Association (KCMA) and Select Representatives,* dated August 17, 2011.

[10] The confirmation of most facilities was obtained in the following memos in the docket for this action: *Telephone Call with Valspar Regulatory Affairs Manager—Wood Coatings on the Availability and Use of Low- and No-Formaldehyde Coatings,* dated June 24, 2011. Also, one of the major manufacturers of wood furniture coatings, Valspar, does not carry any products that have greater than 1 percent formaldehyde leading to the conclusion that coatings greater than 1 percent formaldehyde are mostly unnecessary in the industry. *http://www.valsparwood.com/valsparwood/msds/msds.jsp.*

[11] For more information, see *Updated Formaldehyde Emissions from Select Wood Furniture Manufacturers,* dated August 3, 2011 and *Impacts of Implementing a Limit on Formaldehyde Usage in the Wood Furniture Manufacturing Operations Source Category,* dated October 19, 2011 in the docket for this rule.

to comply with the alternate formaldehyde use limit.[12] These niche facilities use greater concentrations of formaldehyde to provide products to small specialized markets. The EPA is promulgating this 1 percent formulation formaldehyde limit to ensure that we are not limiting the production of facilities while still encouraging facilities to limit formaldehyde in their coatings and contact adhesives. In support of our proposed CAA section 112(f)(2) residual risk determination, we conducted a risk assessment for the Wood Furniture Manufacturing Operations source category that provided estimates of the Maximum Individual Risk (MIR) posed by the allowable and actual HAP emissions from each source in the category, the distribution of cancer risks within the exposed populations, cancer incidence, hazard index for chronic exposures to HAP with noncancer health effects, and hazard quotients (HQ) for acute exposures to HAP with noncancer health effects. We found that risks remaining after compliance with the MACT standard are acceptable.

In making our proposed ample margin of safety determination under CAA section 112(f)(2), we subsequently evaluated the risk reductions and costs associated with various emissions control options to determine whether we should impose additional standards to reduce risks further. We proposed a standard that would limit the use of formaldehyde to 400 pounds per rolling 12 month period because we projected that such a limit would lead to reductions in cancer risks and the potential for acute noncancer health effects. Specifically, we estimated that the limit would reduce formaldehyde emissions by an estimated 9.46 tpy from the baseline level of 20.125 tpy. We also estimated the maximum individual incremental lifetime cancer risk would be reduced to approximately 10-in-1 million from a baseline of 20-in-1 million, the estimated cancer incidence due to emissions from the source category would be reduced by about 15 percent nationwide, and the estimated maximum acute HQ would be reduced from 7 to 3, based on the Reference Exposure Levels (REL) for formaldehyde, and from 0.35 to 0.15, based on the acute exposure guideline level (AEGL–1) for formaldehyde. We believed that there would be either no or minimal additional costs associated with this option, as the cost of low-formaldehyde coatings and adhesives are approximately equal to other coating and adhesive products containing larger quantities of formaldehyde. Also, we believed there were minimal costs associated with the recordkeeping and reporting requirements for compliance with the rule.

Our estimates of the source category maximum cancer risks have changed since proposal due to information received during the comment period. One facility that was included in the risk analysis at proposal has been determined to not be part of the Wood Furniture Manufacturing source category. The facility is a manufacturer of wood and melamine bowls and food service supplies and is not a wood furniture manufacturer. At proposal, the MIR estimated for the bowl manufacturing facility was 20 in-1-million due to formaldehyde emissions, based on actual emissions. This facility MIR was the highest in the source category. With the elimination of the bowl manufacturing facility from the category, the source category MIR is 10 in-1-million due to emissions of ethylbenzene and formaldehyde, based on actual emissions. The bowl manufacturing facility also was one of two facilities for which we estimated an acute HQ of 7 for formaldehyde. The maximum acute formaldehyde HQ of 7 for the other facility in the source category is unchanged.

Since proposal we also have further evaluated acute exposures resulting from emissions from facilities in the source category. To better characterize the potential health risks associated with estimated worst-case acute exposures to HAP, and in response to a key recommendation from the Science Advisory Board's (SAB) peer review of the EPA's RTR risk assessment methodologies,[13] we routinely have examined a wider range of available acute health metrics than we do for our chronic risk assessments. This is in response to the acknowledgement that there are generally more data gaps and inconsistencies in acute reference values than there are in chronic reference values. By definition, acute California-Reference Exposure Levels (CA–REL) represent a health-protective level of exposure, with no risk anticipated at or below those levels, even for repeated exposures; however, the health risk from higher-level exposures is unknown. Therefore, when a CA–REL is exceeded and an AEGL–1 or emergency response planning guidelines (ERPG–1) level is available (*i.e.*, levels at which mild effects are anticipated in the general public for a single exposure), we have used them as a second comparative measure. Historically, comparisons of the estimated maximum off-site 1-hour exposure levels have not been typically made to occupational levels for the purpose of characterizing public health risks in RTR assessments. For most chemicals, the 15 minute occupational ceiling values are set at levels higher than a 1 hour AEGL–1, making comparisons to them irrelevant unless the AEGL–1 or ERPG–1 levels are exceeded. This is not the case when comparing the available acute inhalation health effect reference values for formaldehyde.[14]

The worst-case maximum estimated 1-hour exposure to formaldehyde outside the facility fence line for this source category is 0.47 mg/m^3. This estimated worst-case exposure exceeds the 1-hour REL by a factor of 8 (HQ_{REL} = 8) and is below the 1-hour AEGL–1 (HQ_{AEGL-1} = 0.4). Although this exposure estimate does not exceed the AEGL–1, it exceeds the workplace ceiling level guideline for the value developed by the NIOSH[15] "for any 15 minute period in a work day" (NIOSH REL-ceiling value of 0.12 mg/m^3; HQ_{NIOSH} = 4). Additionally, the estimated maximum acute exposure exceeds the Air Quality Guideline value that was developed by the World Health Organization[16] for 30-minute exposures (0.1 mg/m^3; HQ_{WHO} = 5). The estimated HQ equals 1 when the ACGIH TLV–Ceiling value (0.37 mg/m^3), a value defined as "not to be exceeded at any time," is compared to the worst-case acute exposure screening level.[17] As we proposed, the EPA concludes that the

[12] A representative of KCMA stated that there are facilities that use coatings and contact adhesives with higher concentrations of formaldehyde. For more information see, *Conversation with a Representative of Kitchen Cabinet Manufacturers Association (KCMA) Regarding Add-On Control Devices and High Formaldehyde Concentration in Coatings*, dated June 23, 2011 in the docket for this action.

[13] The SAB peer review of RTR Risk Assessment Methodologies is available at: *http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/the EPA-SAB-10-007-unsigned.pdf.*

[14] U.S. the EPA. (2009) Chapter 2.9, *Chemical Specific Reference Values for Formaldehyde in Graphical Arrays of Chemical-Specific Health Effect Reference Values for Inhalation Exposures (Final Report).* U.S. Environmental Protection Agency, Washington, DC, the EPA/600/R–09/061, and available online at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=211003.*

[15] National Institutes for Occupational Safety and Health (NIOSH). Occupational Safety and Health Guideline for Formaldehyde; *http://www.cdc.gov/niosh/docs/81-123/pdfs/0293.pdf*

[16] WHO (2000). Chapter 5.8 Formaldehyde, in Air Quality Guidelines for Europe, second edition. World Health Organization Regional Publications, European Series, No. 91. Copenhagen, Denmark. Available on-line at *http://www.euro.who.int/_data/assets/pdf_file/0005/74732/E71922.pdf.*

[17] EPA considers this HQ of 1 not to represent an exceedance of the ACGIH value.

risk posed by the source category is acceptable. Our estimate of maximum individual cancer risk for this source category has decreased since proposal. This decrease is due to a miscategorization of a facility within the source category. While our screening for acute impacts has identified the potential for acute formaldehyde exposures to exceed some public health and occupational exposure guidelines at some wood furniture facilities, after considering the limited extent to potential exposures, the fact that the maximum estimate of acute risk has not changed, the fact that one of these facilities no longer uses formaldehyde, and the conservative nature of this screening process, these additional estimates do not change our overall judgment of risk acceptability. As explained in the proposal, in accordance with the approach established in the Benzene NESHAP, the EPA weighs all health risk measures and information considered in the risk acceptability determination, along with the costs and economic impacts of emissions controls, technological feasibility, uncertainties, and other relevant factors, in making our ample margin of safety determination and deciding whether standards are necessary to reduce risks further. Considering all of this information, in particular our revised estimates of the maximum cancer risks associated with the Wood Furniture Manufacturing source category and our revised estimate of the costs of additional controls that would reduce risk further, the EPA has determined that additional standards under CAA section 112(f)(2) are not necessary to provide an ample margin of safety to protect public health. We further note that we are finalizing standards under our CAA section 112(d)(6) authority that, while not expected to result in further reduction in current emissions or risk levels, are expected to reduce the emissions that would have been allowed under the 1995 MACT standard.

2. *Advances in Spray Technology*

The EPA proposed to prohibit the use of conventional spray guns, as defined by the 1995 Wood Furniture Manufacturing NESHAP, pursuant to CAA section 112(d)(6). This final rule promulgates this ban on conventional spray guns with one modification. Based on comments received, we are retaining an existing provision allowing the use of conventional spray guns when the overspray is routed to a control device. As reflected in the comments, some facilities are using overspray from conventional spray guns to partially fuel control devices such as RTOs. This exception from the ban allows facilities to avoid having to supplement fuel to a control device. The efficiency of the control device more than sufficiently reduces excess emissions associated with the decreased spray efficiency of conventional spray guns.[18] This exception for control devices is the sole exception for conventional spray gun use maintained from the 1995 NESHAP.

The EPA estimates that the switch to high efficiency spray guns from conventional spray guns does not incur a cost burden due to decreased product consumption and cost. Some of the high efficiency spray devices are more costly than conventional guns, but the savings in coating costs attributed to the increased spray efficiency more than compensates for increased cost of spray technology. Because the EPA lacks data regarding the number of conventional spray guns used in the industry and the change of spray efficiency in replacing conventional spray technology, we cannot quantify emissions reductions due to changing spray technology. For further information regarding cost and emission reductions, refer to the proposed preamble of this rulemaking.

V. Summary of Significant Comments and Responses

In the proposed action, we requested public comments on our residual risk reviews, our technology reviews, proposed amendments related to periods of SSM, the proposed prohibition of conventional spray guns in the wood furniture manufacturing industry, the proposed limit on formaldehyde use in coatings and contact adhesives for the wood furniture manufacturing industry and clarification of rule provisions. We received written comments from 18 commenters. Our responses to the public comments that changed the basis for our decisions, or are otherwise significant, are provided below.[19]

[18] A typical transfer efficiency of an HVLP gun is 65–80 percent compared to 25–45 percent for conventional guns under similar conditions. This is a difference of 40 percent spray efficiency. When compared to an estimate of 90 percent efficiency of an add-on control device, the control device more than compensates for the 40 percent reduction in efficiency of guns. For more information on transfer efficiencies of spray technologies, see the memo to the docket, *Impacts of Prohibiting the Use of Conventional Spray Guns in the Wood Furniture Manufacturing Operations Source Category*, dated October 29, 2010.

[19] See *Summary of Public Comments and Responses for Shipbuilding and Ship Repair (Surface Coating) and Wood Furniture Manufacturing Operations NESHAP, dated October 31, 2011*, for summaries of all comments and our responses to them.

A. Comments for Both Shipbuilding and Ship Repair (Surface Coating) and Wood Furniture Manufacturing Operations

Comment: A commenter pointed out that the EPA's own data show greater emissions reductions are being achieved and able to be achieved. According to the commenter, the EPA recognizes that certain sources have "achieved" a level of "actual" emissions that is below the level allowed under the existing MACT standards. The commenter further states that the EPA explains that "the 'actual' emission levels are often lower than the emission levels that a facility might be allowed to emit and still comply with the MACT standards." The commenter says that the EPA's expectation that sources in these two categories are generally operating at half the level of emissions allowed under the existing MACT standard is at the core of its emission data analysis. Once the EPA has this information, it must factor this into the technology review under section 112(d)(6). Doing so should lead the EPA to revise the existing MACT for both source categories to require additional emission reductions.

The commenter further states that as part of the required section 112(d)(6) rulemaking, the EPA can have no possible justification for failing to recalculate the MACT floors based on new technology or emission reductions now achieved by these source categories.

The Court in the Hazardous Organic NESHAP (HON) decision stated that it did "not think the words 'review, and revise as necessary'" required the EPA to recalculate the floors "from scratch" in that case. *NRDC*, 529 F.3d at 1084. In short, the *NRDC* Court expressly declined to decide whether the EPA was required to recalculate floors where, as here, there have been developments in practices, processes, and control technologies.

As already noted above, for these source categories, there are such "developments." Therefore, the EPA cannot rely on the HON case to evade its duty to satisfy section 112(d)(6). The HON case did not authorize the EPA to ignore data showing that significant emission reductions below the "MACT-allowable" emissions level have been "achieved" in practice. Even under *NRDC*—assuming *arguendo* that its section 112(d)(6) holding is in any way relevant here—section 112(d)(6) requires the EPA to recalculate the MACT floor when there have been advances in technology (after taking account of the factors listed in section 112(d)(6)), and when there is

information showing that greater emission reductions are "achieved in practice." Commenters contend that, based on the information the EPA has, it is therefore "necessary" for the EPA to strengthen the existing MACT floor to ensure it now complies with section 112(d)(2)–(3).

The EPA must consider and address whether the existing MACT, including the floor, remains lawful in view of the greater levels of emission reductions that have been achieved.

Response: The commenter is mistaken on several grounds. First, the commenter asserts that "the EPA recognizes that certain sources have 'achieved' a level of 'actual' emissions that is below the level allowed under the existing MACT standards" and cites the Notice of Proposed Rulemaking preamble at 75 FR at 80227. This was a qualitative, introductory statement about how the NEI and other sources of data typically contain estimates of actual emissions that are "often" lower than allowable emissions. The statement was not specific to Wood Furniture or Shipbuilding facilities or data and in any event did not contain any quantitative determination about actual emissions levels.

Second, the commenter asserts that the EPA has an "expectation" that wood furniture and shipbuilding sources are "generally operating" at half of allowable emissions and once the EPA has this information, it must use it under CAA section 112(d)(6) to revise MACT standards, including recalculating MACT floors under section 112(d)(2)–(3). The comment apparently refers to the MACT allowable to actual emissions ratio developed for the source categories in this rulemaking. The commenter is incorrect in characterizing this ratio as a determination of the level of actual emissions achieved in practice in either source category. The actual to allowable ratio represents the lowest concentration of HAP in a coating available to the industry compared to the maximum allowed under the MACT. The allowable ratio is used for providing a worst-case scenario for estimating allowable emissions from the source. As clarification, for these coating rules, the concentrations of HAP in the coatings are considered the emissions from the source.

Third, the commenter is incorrect in asserting that the EPA must recalculate MACT floors under CAA section 112(d)(2)–(3). As explained in prior RTR rulemakings, the EPA does not read 112(d)(6) as requiring a reanalysis or recalculation of MACT floors. See proposed National Emission Standards for Coke Oven Batteries (69 FR 48388, 48351 (August 9, 2004)). Instead, we interpret section 112(d)(6) as essentially requiring us to consider developments in pollution control in the industry ("taking into account developments in practices, processes, and control technologies"), and assessing the costs of potentially stricter standards reflecting those developments. We read this provision as providing the EPA with substantial latitude in weighing these factors and arriving at an appropriate balance in considering revisions to our standards. This discretion also provides us with substantial flexibility in choosing how to apply modified standards, if necessary, to the affected industry.

The EPA reviewed other potential developments in practices, processes and control technologies for the Wood Furniture Manufacturing Operations and Shipbuilding and Ship Repair (Surface Coating) source categories and evaluated costs of potentially more stringent standards reflecting any such developments.[20] The EPA believes this review and the revisions finalized in this rulemaking satisfy the EPA's obligations under CAA 112(d)(6) for the Wood Furniture and Shipbuilding source categories.

B. Wood Furniture Manufacturing Operations

Comment: A commenter stated the EPA has provided no rational explanation for refusing to update the technology standards for both categories to meet the CAA section 112(d)(6) requirement, at minimum, by matching the limits of what sources have achieved and what other jurisdictions have required. The commenter stated:

> We urge the EPA to do so in the final rule. Where, as here, there are "significant developments" in technology, and where, as here, sources have achieved lower levels of emissions "in practice" than are "MACT-allowable," it is abundantly clear that § 112(d)(6) requires the EPA to revise its standards in accordance with CAA § 112(d)(2)–(3), (6), 42 U.S.C. § 7412(d)(2)–(3), (6).

The commenter also inquires why the EPA did not adopt more stringent standards based on other regulating bodies within the country.

Response: The EPA has concluded the technology review for the wood furniture manufacturing operations NESHAP by setting a formaldehyde limit based on formulation (1 percent by weight) of finish coatings and contact adhesives with a compliance alternative using no more than 400 pounds of formaldehyde per 12 months. Also under the technology review, we are adopting a restriction of conventional spray guns limiting use to when emissions from finishing applications are routed to a control device. The commenter refers to volatile organic compounds (VOC) standards of the Bay Area and South Coast Air Quality Management Districts (BAAQMD and SCAQMD). These two standards are nearly identical in VOC formulation limits. Through the RTR process, the EPA evaluates risk and technology developments associated with HAP for the source categories under consideration. Hazardous air pollutants and VOC describe different sets of compounds, although a large subset of VOC are considered HAP. As discussed in the preamble of the proposed rule, we estimate that of all VOC in wood furniture coatings, 50 percent on average are HAP. This is an average value that in fact varies from facility to facility and coating to coating, depending on the facility's use of coatings specific to their operation. This is especially true for many niche companies. The EPA acknowledges BAAQMD and SCAQMD implementation of VOC limits, but these limits are not justified as nation-wide standards to reduce HAP from Wood Furniture Manufacturing. They are not technically feasible to be implemented nationally based on different operating and environmental conditions as well as the cost-effectiveness. By the commenter's own admission, there are facilities that are having a difficult time complying with the BAAQMD standard within its region. Moreover, based on available information, the EPA maintains that both area regulations are not cost effective as national standards to reduce HAP. As discussed in the preamble to the proposed rule, adoption of the BAAQMD VOC limits would result in 56 tpy of HAP reduction at a cost of $30,000 per ton. Although the commenter asserts based on a

[20] The EPA's review and analysis for the shipbuilding source category can be found in *Affordability of Add-on Controls for Surface Coating Operations at Shipbuilding and Ship Repair Facilities*, dated 10/28/2010, and for the wood furniture surface category in *Affordability of Lower VHAP Coating and Add-on Controls for Wood Furniture Manufacturing Operations*, dated October 28, 2010. Other significant memos describing the EPAs technology review are:

Developments in Practices, Processes, and Control Technologies for Wood Furniture Manufacturing Operations, dated August 24, 2010; *Impacts of Prohibiting the Use of Conventional Spray Guns in the Wood Furniture Manufacturing Operations Source Category*, dated October 19, 2010;

Cost Analyses for Control Options, dated September 27, 2010; *Cost Analyses for Add-on Controls for Surface Coating Operations at Shipbuilding and Ship Repair Facilities*, dated September 9, 2010.

conversation with BAAQMD staff that companies in the area are generally complying with BAAQMD limits, the EPA already assumed compliance when we estimated HAP reductions and cost-effectiveness of the BAAQMD limits. We have not changed our conclusion that the BAAQMD and SCAQMD regulation are not cost effective as a national standard.

Comment: Two commenters stated that the facility with the highest reported formaldehyde emissions (Kitchen Kompact located in Jeffersonville, Indiana) is not a representative wood coating manufacturing facility.

The commenters offered the following reasons:

a. The facility finishes products 4 days a week (as opposed to the EPA's 5-day assumption);

b. The facility uses uses higher VOC coating without a control device; and

c. The facility has all operations at one facility (other large facilities may spread operations over several facilities).

Another commenter believed that it is arbitrary for the EPA to set the formaldehyde limit based on data indicating that 3 percent (more likely 1 percent, see below) of facilities have formaldehyde emissions that could result in exceedances of the acute REL. The commenter offered the following reasons why the EPA's conclusion that 11 facilities (about 3 percent of the facilities) have formaldehyde emissions that could result in exceedances of the acute REL is problematic:

a. The EPA identified four facilities for emissions verification, two of which were reported to have formaldehyde emissions. One of these two, Chromcraft, no longer uses coatings that contain or emit formaldehyde. The other, Kitchen Kompact, emits less formaldehyde than reported and is not a representative facility. Both facilities are problematic and indicate that the facility data used in the risk assessment are suspect.

b. Three of the 11 facilities either no longer use formaldehyde-containing coatings or contact adhesives (Chromcraft) or have lower production than the EPA identified (Kitchen Kompact and Legacy Cabinets). Removing Chromcraft, only 10 facilities, or 2.5 percent of the total, have emissions that could result in exceedances of the acute REL.

c. The refined modeling approach that used aerial photographs of the facilities identified two major problems with the Human Exposure Model-3 (HEM–3) screening results:

• The REL, for several facilities, were overestimated due to global positioning system errors and;

• Moving the "polar ring" has a significant impact on the risk assessment. An evaluation of the aerial map indicated that the REL needed to be lowered in some cases by as much as 74 percent. While developing refined acute risks based on review of aerial maps is better than the screening approach, it is subjective at best.

d. Three of the 10 facilities had refined predicted acute risks greater than 3. The remaining 7 facilities had refined predicted acute risks of less than 3, and a majority of these had predicted acute risks just above 1 (1.5, 1.5, 1.6,[21] 1.8). The commenter suggested that the risks for these facilities should be discounted.

After removing these data points discussed above, the commenter noted that there are six facilities (approximately 1 percent of the facilities) with acute risks greater than 1. The commenter noted that setting a standard based on six facilities (or 1 percent of all wood furniture facilities) is unjustified and arbitrary.

Response: The EPA acknowledges that there have been changes to formaldehyde emissions since 2005. According to the comments received as well as phone conversations with several facilities, the EPA has received indications that facilities have changed and lowered formaldehyde emissions, subsequent to the 2005 NEI data. These updates, however, are not being used to replace the 2005 NEI data because data were not provided to support the assertions. Because the data are unverified, the EPA used source data from 2005 NEI to keep a verified source for purposes of risk assessment. As discussed elsewhere in this preamble, we are not adopting any new or additional requirements based on the risk assessment under section 112(f). We have found risk to be acceptable for this rule making.

Comment: Multiple commenters offered comments on the use of formaldehyde dose-response values.

Two commenters supported the use of the Integrated Risk Management System (IRIS) dose-response value for formaldehyde in the risk assessment.

One of the commenters stated that it is not only appropriate for the EPA to end its use of the Chemical Industry Institute of Toxicology (CIIT) Centers for Health Research risk value for formaldehyde emissions, doing the contrary would be arbitrary, capricious and unlawful. The commenter supported the IRIS value because it is more than 2,000 times greater than the CIIT value and thus more health-protective.

Alternatively, six commenters did not support the use of "outdated" and "overly conservative" models, such as that used to derive the IRIS dose-response value for formaldehyde.

One commenter stated that the EPA must use the best available science in its risk assessment, which is not the IRIS value. The commenter noted that the EPA has previously determined that the IRIS value "no longer represents the best available science in the peer reviewed literature." 69 FR 18,327, 18,333 (Apr. 7, 2004). It was stated that the decision to discontinue use of CIIT model is inappropriate. The CIIT model should continue to be used to inform formaldehyde risk assessments. The criticisms of the model by Crump and colleagues lack foundation because the manipulations and alterations of the model on which they are based did not have an adequate basis in the underlying biology.

Response: In 2004, the EPA determined that the Chemical Industry Institute of Toxicology (CIIT) cancer dose-response value for formaldehyde (5.5×10^{-9} per $\mu g/m^3$) was based on better science than the IRIS dose-response value (1.3×10^{-5} per $\mu g/m^3$), and we switched from using the IRIS value to the CIIT value in risk assessments supporting regulatory actions. Based on subsequent published research, however, the EPA changed its determination regarding the CIIT model, and in 2010 the EPA returned to using 1991 IRIS value. The National Academy of Sciences (NAS) completed its review of the EPA's draft assessment in April of 2011 *(http://www.nap.edu/catalog.php?record_id=13142)*, and the EPA has been working on revising the formaldehyde assessment. The EPA will follow the NAS Report recommendations and will present results obtained by implementing the biologically based dose response (BBDR) model for formaldehyde. The EPA will compare these estimates with those currently presented in the External Review draft of the assessment and will discuss their strengths and weaknesses. As recommended by the NAS committee, appropriate sensitivity and uncertainty analyses will be an integral component of implementing the BBDR model. In the interim, we will present findings using the 1991 IRIS value as a primary estimate, and may also consider other information as the science

[21] The value of 1.6 refers to Legacy Cabinets which, as the commenter asserts, no longer has any coatings or contact adhesives with formaldehyde in them.

evolves. The EPA notes that risk estimates based on both the IRIS and the CIIT unit risk estimates for formaldehyde were presented in the proposal for this final rule and that the risks were acceptable in both cases.

Comment: A commenter stated that the best available science indicates that formaldehyde in outdoor air does not present a risk to human health.

In support of their assertion, the commenter quoted WHO which stated that "[i]n ambient air, formaldehyde is quickly photo-oxidized in carbon dioxide. It also reacts very quickly with the hydroxyl radicals to give formic acid. The half-life estimated for these reactions is about one hour depending on the environmental conditions." (WHO, 2010, at 103). Further, WHO concluded that because levels in ambient air are low, outdoor air does not contribute significantly to indoor pollution. *Id.* at 108. Therefore, the EPA's proposed cap on formaldehyde use is an unnecessary restriction that will not reduce residual risk, if any, to public health.

Response: Everyone is exposed to small amounts of formaldehyde in air and some foods and products. Nasal and eye irritation, neurological effects, and increased risk of asthma and/or allergy have been observed in humans breathing 0.1 to 0.5 ppm. Eczema and changes in lung function have been observed at 0.6 to 1.9 ppm. The Department of Health and Human Services (DHHS) has determined that formaldehyde is a known human carcinogen based on human and animal inhalation studies.[22] The EPA considers formaldehyde as a "Probable Human Carcinogen" in IRIS; *http://www.epa.gov/iris/subst/0419.htm.* The International Agency for Research on Cancer (IARC) classifies formaldehyde as a human carcinogen; *http://monographs.iarc.fr/ENG/Monographs/vol88/index.*

Ambient modeling of formaldehyde in the National Scale Air Toxics Assessment (NATA) at major urban centers indicate that formaldehyde exposures over the long term for excess cancer risks could be up to 100 in a million with a national average of 20 in a million based upon the current IRIS Unit Risk Estimate (URE). Monitoring at the National Air Toxics Trends Sites for formaldehyde are in good agreement with the NATA, refer to the following Web site; *http://www.epa.gov/ttn/atw/nata2005/compare.html.*

[22] This is according to the Agency for Toxic Substances and Disease Registry. *http://www.atsdr.cdc.gov/toxfaqs/tf.asp?id=219&tid=39.*

The dispersion modeling for wood furniture manufacturing and shipbuilding does not incorporate photochemical decay. The EPA conducted a sensitivity analysis and determined this feature in AERMOD[23] does not have a significant effect on near-field exposures and is most relevant for population exposures in the far field especially for pollutants with half-lives less than 30 minutes. The rate of decay is also very dependent temporally with less reactivity occurring during evening hours as well as during colder seasons. For more information on the sensitivity analysis, please refer to Section 4.6: Sensitivity Analysis—Atmospheric Chemistry in "the EPA's Risk and Technology Review (RTR) Risk Assessment Methodologies," that was reviewed by the EPA's SAB; *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html.* Based upon the rate of decay for formaldehyde varying from 1 hour to 16 hours and the fact that the MIR location for this source category is located within 300 meters of the emission source, we find that photochemical decay will not have an effect on the MIR.

Comment: A commenter stated the EPA's sole justification for setting the formaldehyde limit at 400 lbs per rolling 12-month period appears to be the fact that this level is already contained in the existing MACT as a work practice requirement. Specifically, the commenter contended:

> The EPA has stated that adopting this level as an emission standard would create "either no or minimal additional costs." *Id.* at 80,247. This number was chosen in 1995, however. Where this number came from initially is unclear. While it may be convenient for industry to use a level with which it is already familiar and that would incur little or no extra cost, the EPA has not provided a reasoned explanation based on the required statutory health-based criteria for choosing this limit, rather than a more stringent limit. The record does not show why this is the appropriate limit to set as a residual risk standard in today's world.
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> The EPA must complete this analysis and set an appropriately protective standard to satisfy CAA section 112(f)(2). Specifically, the EPA must consider and address how much emissions would be reduced if the EPA set a lower standard, and what level of emission standard is required to provide an "ample margin of safety." 42 U.S.C. § 7412(f)(2). The EPA must address what emission standard would be needed to bring the MIR down to 1-in-1-million as the statute directs. Id. The EPA must address what standard is needed "to provide maximum feasible protection against risks to health" by "protecting the greatest number of persons possible" to a lifetime risk level no greater than 1-in-1 million. 75 Fed. Reg. at 80,223 (quoting Benzene NESHAP). The need for this analysis is amplified by the fact that the EPA has recognized numerous "uncertainties related to the risk assessments, particularly for formaldehyde and glycol ether emissions." *Id.* at 80,242–43. For example, the EPA has stated that it is concerned that its risk analysis has failed to account for additional formaldehyde emissions that likely occur during curing and gluing. *Id.* at 80,243. The uncertain amount of additional risk unaccounted for provides another reason for the EPA to set a more protective formaldehyde emission standard than the level chosen as a work practice standard in 1995.

Response: The EPA is not finalizing the 400 pounds per rolling 12-month period formaldehyde use limit as proposed under 112(f) of the CAA. See section III of the preamble for a discussion of our final action.

The EPA is promulgating a formaldehyde standard under section 112(d)(6). Please refer to earlier descriptions in the preamble for further justification of section 112(d)(6) of the CAA. All wood furniture coatings and contact adhesives must be low- or no-formaldehyde (concentration not to exceed 1 percent by weight formaldehyde) or, as a compliance alternative, formaldehyde emissions from wood furniture facilities must not exceed 400 pounds per rolling 12-month period. The compliance options are designed to promote continuing reductions in formaldehyde emissions from wood furniture without requiring equipment changes that are not cost effective or limiting in production. The formaldehyde limits will avoid constraining the production of wood furniture products facilities while encouraging facilities to maintain or decrease levels of formaldehyde within coatings and contact adhesives.

The 400 pounds per 12 month period formaldehyde limit is based on the threshold level in Table 5 of the 1995 NESHAP, which itself was a result of negotiations with industry. In this RTR, we took the familiar numerical threshold for formaldehyde emissions and made it a level not to exceed as a compliance alternative. This was done, in the proposal, to reduce the HQ of formaldehyde from 7 to 3 in a cost effective manner. Between proposal and promulgation, it became clear through public comments that this limit was not cost effective for the source category. As discussed in greater detail of section IV of this preamble, this limit is now a compliance alternative under section 112(d)(6).

[23] AERMOD was developed by the American Meteorological Service (AMS)/EPA Regulatory Model Improvement Committee (AERMIC). This is the preferred model by EPA for modeling point, area and volume sources of continuous air emissions from facilities.

The science is unclear as to the degree of formaldehyde curing under different environmental conditions. We did not receive any public comments containing substantive or relevant emissions information on formaldehyde emissions from curing at wood furniture facilities. Until there is more data relevant to how cure formaldehyde is formed and/or in what quantities, we are unable to set limits for such emissions.

Comment: Five commenters disagreed with the 400 pound per 12 month period formaldehyde limit. Two of the commenters noted that limiting formaldehyde emissions from the wood furniture manufacturing operations source category is not supported by the EPA's risk analysis and is therefore arbitrary. One commenter noted that the total estimated cancer incidence due to actual emissions is 0.005 excess cancer cases per year or one case in every 200 years.

Another commenter further stated that the limit is not necessary because formaldehyde emissions are likely to decrease further during the 2-year compliance period, without any further regulations.

A commenter stated that the EPA is not justified in adopting this standard under CAA section 112(f)(2)(A) or CAA section 112(d)(6). On a related note, a different commenter questioned the authority of the EPA to establish a 400 pounds per year limit on formaldehyde emissions. The basis for the commenter's assertion is that a 400 pound limit will limit production at facilities and will inhibit companies from meeting industry performance standards. A commenter noted that the EPA chose the 400 pound per year formaldehyde limit based on Table 5 of the MACT standard (List of VHAP of Potential Concern Identified by Industry). Currently, facilities that exceed their baseline level would need no further explanation to permitting authorities if the exceedance is no more than 15 percent above the baseline, or if the use is below the level in Table 5. According to the commenter, the EPA did not note the number of facilities that use the formaldehyde limit versus the baseline exceedance option. Without more data, it is not known if facilities use the 400 pound per year limit. The commenter assumed that most facilities comply via the exceedance of baseline option and not the 400 pound per year limit.

A commenter also stated that the EPA improperly presumed a "one-size fits all" approach to coatings and adhesives is feasible in the manufacture of wood furniture/cabinet products. The EPA failed to take into account the performance, quality and customer requirements of these manufactured goods. The coatings and adhesives used for cabinet manufacture are specialized and may contain higher amounts of formaldehyde due to unique customer requirements.

A commenter noted that based on the data in an EPA memorandum,[24] the difference in price between coatings with formaldehyde and those that are formaldehyde-free is $3.02 per gallon. The commenter assumed a 1 percent formaldehyde content in the lower priced coating and a coating density of 8 pounds per gallon. The $3.02 per gallon additional cost for a formaldehyde-free coating would reduce formaldehyde emissions by 0.08 pounds for a cost of $37.75 per pound of formaldehyde eliminated or $75,500 per ton.

The commenter also evaluated the replacement cost for a topcoat containing 0.25-percent formaldehyde with a material containing only 0.005 percent formaldehyde. The price differential of $3.58 per gallon resulting in a cost of over $365,000 per ton of formaldehyde eliminated.

The commenter noted the high cost of replacement of contact adhesives. Based on the relatively low formaldehyde content in the current materials used, an incremental cost of only $1 to $2 per gallon could result in a cost exceeding $20,000 per ton.

Response: Based on information received in the comments and further inquiry of the effects of the proposed limit of 400 pounds formaldehyde per rolling 12-month period, the EPA has revised the standard to require the formaldehyde content of coatings and contact adhesives to be less than or equal to 1 percent by weight with an alternate compliance option of the 400 pounds per rolling 12-month period formaldehyde use limit, as explained elsewhere in the preamble.

This approach is promulgated under the technology review requirements under the CAA section 112(d)(6). Risk was determined to be acceptable under section 112(f)(2) of the CAA (residual risk). This technology rule will not limit production or result in significant costs for high production facilities and will encourage further reductions in the future without compromising the integrity of product.

The EPA has information that indicates that most facilities will be able to cost-effectively comply with the 1 percent by weight formaldehyde limit.[25] A commenter asserts that coatings and contact adhesives that are 1 percent formaldehyde are cost effective. This level of formaldehyde will be sufficient to create the cross-linking nucleation that provides durability to wood furniture products in many cases. By also having a formulation restriction as an alternative to the 400 pound per year limit, there will not be a restriction of production.

Comment: Multiple commenters offered comments related to the EPA's estimate of the cost for meeting the proposed formaldehyde standard.

One of the commenters noted that the EPA does not adequately support its cost estimate. The commenter stated that the EPA provided no data or analysis to support its assumption that all facilities operate in the same way or that the use of no- or low- formaldehyde coatings and contact adhesives would be suitable for use by all facilities.

The commenter further noted that the EPA's "cost analysis" consists of price information, from one supplier, of 13 no- or low-formaldehyde coatings that the agency considers to be suitable for use in wood furniture manufacturing operations.[26] The commenter noted that the EPA does not analyze whether the available coatings can be used in all applications or would meet industry performance standards.

A different commenter stated that the technical and cost analyses the EPA puts forth in support of the 400 pound per year limit are not backed up by any critical analysis or actual data. According to the commenter, this analysis amounts to the assertion that, "because some facilities are doing it, all facilities should be able to do it. This is an empty 'analysis' that provides no support for the proposed 400 lb per year limit. On top of that, the EPA also asserts that the new standard can be met 'at little or no extra cost.'" The commenter stated that a much more robust cost analysis would be needed to justify imposing an additional emissions limitation.

Moreover, two commenters noted that the EPA does not address the additional costs incurred due to the potential need

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[24] See: *Impacts of Implementing a Limit on Formaldehyde Usage in the Wood Furniture Manufacturing Operations Source Category*, October 19, 2010. This document is available in the docket for this rulemaking.

[25] One of the major manufacturers of wood furniture coatings, Valspar, does not carry any products that have greater than 1 percent formaldehyde leading to the conclusion that coatings greater than 1 percent formaldehyde are mostly unnecessary in the industry. *http://www.valsparwood.com/valsparwood/msds/msds.jsp*

[26] See U.S. the EPA, Memorandum, *Impacts of Implementing a Limit on Formaldehyde Use in the Wood Furniture Manufacturing Operations Source Category* dated October 19, 2010 in the docket for this action.

for new equipment, the significant expenses to adapt to a new finish material.

Response: Based on information received in comments, we have adopted a 1 percent by weight formaldehyde limit with a 400 pounds formaldehyde per rolling 12-month period alternative compliance limit that allows wood furniture manufacturers to use their discretion to reformulate to lower formaldehyde coatings and contact adhesives while not necessitating the expense of production line reconfiguration. As discussed above, we have updated the cost-effectiveness analysis for the proposed formaldehyde limit and concluded that the 400 pound per 12 month limit as proposed would not be cost effective.[27]

Using low-formaldehyde coatings and contact adhesives reflects developments in technology and was described in the proposal as the method to achieve compliance with the proposed 400 pounds formaldehyde per rolling 12-month period. A limit of 1 percent formaldehyde in coatings and adhesives allows facilities the flexibility to use coatings and adhesives that are suitable for a range of different products, from cabinets to home furnishings, without compromising their quality, cost or production.[28] Also, in many cases, the 1 percent formaldehyde limit will allow flexibility in different types of line configurations.[29]

Comment: Multiple commenters noted that the EPA overestimated the health risk from glycol ethers by using ethylene glycol methyl ether as the representative glycol ether.[30] Given that the use of glycol ethers other than ethylene glycol methyl ether is the norm for the industry, the risk associated with this class of compounds is overstated in the EPA's analysis and no additional regulation of glycol ethers is warranted. The table contains a summary of speciated glycol ethers that are less toxic than ethylene glycol methyl ether. This shows, in the commenter's opinion, the EPA's overestimation of the health risk from these compounds.

One commenter offered another assessment approach for glycol ethers:

> A more reasonable assessment of glycol ethers would be the example based on data from all facilities of a large wood furniture manufacturing company. Glycol ether emissions in 2010 totaled 3.76 tons, of which over 95 percent of the emissions were ethylene glycol monobutyl ether, with the remainder comprising diethylene glycol phenyl ether, diethylene glycol butyl ether and phenoxyethanol. Based on the preponderance of ethylene glycol monobutyl ether in these emissions, a risk assessment using the significantly higher REL for ethylene glycol monobutyl ether (REL = 14 vs. REL for ethylene glycol methyl ether of 0.093 ref: *http://www.oehha.ca.gov/air/pdf/acuterel.pdf*) would conclude that the risk from glycol ethers is approximately 150 times lower than the EPA's analysis shows. Even if the REL for another glycol ether—Ethylene Glycol Monoethyl Ether, REL 0.37—were used, the risk associated with glycol ethers would be reduced by a factor of 4.

A second commenter offered a different option. The commenter recommended that the HQ derived by the EPA for Propyl Cellosolve® (ethylene glycol mono-n-propyl ether (EGME)) be recalculated using an REL they propose for ethylene glycol phenyl ether (EGPE). The commenter contends that information provided in their comments demonstrates that sufficient information exists to derive an REL for EGPE, which would be more appropriate for risk management than the REL for EGME.

Response: As we acknowledged in the proposal, the use of the EGME REL in our acute risk screening assessments provided us with a conservative (*i.e.*, health-protective) estimate of potential acute health risks from glycol ethers when the exact speciation profile of emitted glycol ethers was uncertain. For this source category, approximately 70 percent of facilities reporting glycol ether emissions reported them without any speciation information. Since there are no AEGL or ERPG values available for any glycol ethers, this further limits our ability to interpret the potential acute impacts of glycol ethers. Since this uncertainty remains, the EPA is not convinced that the use of less health-protective assumptions (such as those recommended by the commenters) represents any improvement in the assessment of potential acute impacts. Even so, because of the health-protective nature of our assessment, we do not believe that these estimated worst-case acute glycol ether impacts warrant the adoption of additional control measures.

Comment: A commenter suggested that the EPA either define the term "conventional" or mention the types of spray guns that are to be used to assist the regulated community in complying with this rule. The commenter suggested specific items, mentioned in the Paint Stripping and Miscellaneous Surface Coating Operations rule (Subpart HHHHHH): High-volume low-pressure (HVLP) spray guns, electrostatic applications, airless or air-assisted airless spray guns, or air-assisted airless equivalent technologies.

Another commenter suggested that the EPA exclude the following components from the definition: Handheld non-refillable aerosol containers, touch-up markers, marking pens, and the application of paper film or plastic film which may be pre-coated with an adhesive by the manufacturer. These items are allowed by the miscellaneous metal parts and products NESHAP (subpart MMMM).

Response: The existing Wood Furniture Manufacturing Operations MACT standards define "conventional air spray" as:

> a spray coating method in which the coating is atomized by mixing it with compressed air and applied at an air pressure greater than 10 pounds per square inch (gauge) at the point of atomization. Airless and air assisted airless spray technologies are not conventional air spray because the coating is not atomized by mixing it with compressed air. Electrostatic spray technology is also not considered conventional air spray because an electrostatic charge is employed to attract the coating to the workpiece. 40 CFR 63.801(a).

Many of the above suggestions for specific coating applications are clearly included or excluded by the definition of conventional spray provided in the 1995 NESHAP. The technologies listed above such as touch-up markers, marking pens and manufacturer pre-coated adhesive film are not affected by the ban on use of conventional spray guns because they do not have a spray, *i.e.*, they are not "a spray coating method." Despite certain technologies being incorporated to other rule makings such as subpart HHHHHH, the commenter did not explain why these applications are necessary for this rule making. Examples of compliant spray technology include, but are not limited to HVLP spray guns, low-volume low-pressure guns (LVLP), electrostatic applications, airless and air-assisted airless spray guns. Low-capacity HVLP cup guns may be used for small batch operations.

Comment: A commenter suggested that the EPA clarify in the rule that facilities with controls can continue to use conventional spray guns. Any

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[27] For further detail, see memo to the docket, *Estimated Cost Impact for Wood Furniture Manufacturing Industry to Comply with Proposed Formaldehyde Limit on Coating Operations Wood Furniture Manufacturing RTR*, dated July 15, 2011.

[28] It is necessary for some facilities to minimize levels of formaldehyde in the coating formulation to promote cross-linking nucleation. This process directly affects the quality and durability of the wood furniture. See notes from the *Marsh Furniture Site Visit* in the docket for this action for reference.

[29] For additional information, please see memo to the docket, *EPA Meeting with Kitchen Cabinet Manufacturers Association (KCMA) and Select Representatives*, dated August 17, 2011.

[30] The commenters referred to Table 4 in the EPA's October 22, 2010, memorandum, *Review of Glycol Ether Emissions Associated with Wood Furniture Manufacturing Source Category.*

emissions would be controlled via the control device.

Another commenter noted that several RTOs, which rely on rich VOC waste streams, are being operated in the industry. To impose air-assisted-airless guns reduces RTO efficiency and requires more fossil fuel to be consumed. Regenerative thermal oxidizers are fueled by overspray and fossil fuels; when the quantity of overspray is decreased, the more fossil fuel that is needed to keep the RTO functioning.

Response: The proposed rule has been revised to allow use of conventional spray guns when the overspray is routed to a functioning control device. The efficiency of the control device sufficiently reduces excess emissions associated with the decreased spray efficiency of conventional spray guns.[31]

Comment: Two commenters noted that the EPA offered an incorrect premise that all applicator improvements to increase transfer efficiency of the sprayed material will result in reduced emissions simply due to higher transfer efficiencies. The premise does not consider the low-use application considerations required for trials, touchups and product repairs.

One of the commenters noted:

> HVLP and equivalent high efficiency applicators require larger volumes of premixed materials for application and are best used where large quantities of materials are intended (usually volumes larger than one gallon to as much as 30 gallons) and in production quantity applications where large surface areas are coated. Under large volume spray applications, the high transfer efficiency equipment results in reduced material consumptions resulting in lower operating costs and lower emissions. Under high volume application conditions, there are both economic and environmental advantages for operations to use high transfer efficiency equipment.
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> However, for low use applications such as low volume color stains, trial materials, small touchups and repairs, mixing large batches for use in high transfer efficiency equipment will result in increased material consumption and waste, increased cleanup solvent consumption and waste, and, for catalyzed top coat materials, material loss through restricted pot life. The proposed applicator changes would result in an inability to properly mix small batch work coatings (stains, sealers, topcoats, etc.), resulting in more wasted raw material, increased cleanup material use, waste and emissions and an unnecessary increase in generated waste volume.
>
> Arguably, the use of low volume conventional spray equipment such as cup guns, etc., affords the industry a small volume spray alternative that would otherwise require a part to be re-finished or scrapped entirely. Failed finish repairs with minimal rework and reapplication to the part and in some instances salvage of an otherwise scrapped production part makes production and environmental sense. Indeed small quantity applicators (generally those with a restricted volume of 1.0 U.S. quart or less) may actually result in lower VOC and VHAP emissions due to the restricted use and inherent limited production capability of the application equipment itself.
>
> Such an overreaching requirement for all spray equipment to be of the HVLP spray type or equivalent is not reasonable and does not consider the other adverse environmental impacts discussed above.

Response: First, we note the commenter agrees with the EPA that with large volume spray applications, which the commenter defines as larger than one gallon and in production quantities, high transfer efficiency equipment results in reduced material consumption, lower operating costs and lower emissions.[32] In addition, we find that the application technology is available for small batches of coating to be applied with non-conventional spray guns such as HVLP cup guns. The use of HVLP cup guns will allow for smaller batch mixes. This prevents unneeded coating material going to waste. With the higher spray efficiency associated with non-conventional spray guns, a greater portion of the spray is coating the piece of wood. This means that there is less overspray leading to fewer emissions. Other touch-up applications such as touch-up markers and handheld non-refillable aerosol containers may still be used under the standard. For more information see *Use of Non-Conventional Spray Technology in the Wood Furniture Manufacturing Industry,* dated August 3, 2011 and *Impacts of Prohibiting the Use of Conventional Spray Guns in the Wood Furniture Manufacturing Operations Source Category,* dated October 19, 2010, in the docket for this action.

C. Shipbuilding and Ship Repair (Surface Coating)

Comment: A commenter stated the EPA has provided no rational explanation for refusing to update the technology standards for both categories to meet the CAA section 112(d)(6) requirement, at minimum, by matching the limits of what sources have achieved and what other jurisdictions have required. The commenter stated:

> We urge the EPA to do so in the final rule. Where, as here, there are "significant developments" in technology, and where, as here, sources have achieved lower levels of emissions "in practice" than are "MACT-allowable," it is abundantly clear that § 112(d)(6) requires the EPA to revise its standards in accordance with CAA § 112(d)(2)–(3), (6), 42 U.S.C. § 7412(d)(2)–(3), (6).

The commenter also inquires why the EPA did not adopt more stringent standards based on other regulating bodies within the country.

Response: As explained in the proposal, in accordance with the approach established in the Benzene NESHAP, our analysis of risks for this source category showed that the maximum source-category cancer risks for all facilities are within the range of acceptable risks and that the maximum chronic noncancer risks are unlikely to cause health impacts. The EPA has weighed all health risk measures and information considered in the risk acceptability determination, along with the costs and economic impacts of emissions controls, technological feasibility, uncertainties, and other relevant factors, in making our ample margin of safety determination. The EPA has found the overall level of risk to be acceptable for the source category and the ample margin of safety determination for this source category indicates that potential controls are not cost effective and technically feasible.

Comment: A commenter stated that the EPA has failed to fulfill its CAA section 112(f)(2) duty to fully assess and determine whether the risk from this source category is "acceptable." The EPA concludes that this category creates an MIR of 20-in-1 million based on allowable emissions, and 10-in-1 million based on estimated "actual" emissions. The EPA does not justify its conclusion on the record that this level of risk is acceptable. It simply lists the numbers and different factors, without explaining how it is analyzing these factors or why they have led the EPA to reach its conclusion. The EPA recognizes that disparities in risk exist, with individuals in certain demographic groups, including African Americans and people with income below the poverty level, more likely to experience a higher level of risk. As discussed above, the EPA cannot simply rely on the old Benzene presumption that any

[31] A typical transfer efficiency of an HVLP gun is 65–85 percent compared to 25–45 percent for conventional guns under similar conditions. This is a difference of 40 percent spray efficiency. When compared to an estimate of 90 percent efficiency of an add-on control device, the control device more than compensates for the 40 percent reduction in efficiency of guns. For more information on transfer efficiencies of spray technologies see the memo to the docket, *Impacts of Prohibiting the Use of Conventional Spray Guns in the Wood Furniture Manufacturing Operations Source Category,* dated October 29, 2010.

[32] For more information please see *Impacts of Prohibiting the Use of Conventional Spray Guns in the Wood Furniture Manufacturing Operations Source Category,* dated October 19, 2010, in the docket for this action.

level of risk under 100-in-1 million is acceptable. And, the fact that 4,000 people is a "relatively low" number (*i.e.*, the number estimated to be exposed to cancer risks of 1-in-1 million or greater) does not justify the EPA's proposal of inaction to protect these people. CAA section 112(f)(2) requires the EPA to set standards for the maximum exposed individual. The individuals in this group of 4,000 are the very people whom the law requires the EPA to be concerned about.

Response: We do not consider the 1-in-1 million MIR level as a 'bright line' mandated level of protection for establishing residual risk standards. In determining the ample margin of safety (*i.e.*, the level of the standard), health risk is one factor that we must consider, along with other factors such as cost and technological feasibility. Balancing these and other factors with the ability to achieve meaningful risk reduction is a critical component of the residual risk rulemaking process. We considered reducing risks further but concluded that the technology required, such as a portable or permanent enclosure big enough to accommodate an entire ship or even a section of a ship to capture and control air emissions, would be cost prohibitive for this industry. Although our additional analysis of the demographics of the exposed population shows some disparities in risks between demographic groups for both categories, the EPA has determined that no group is exposed to an unacceptable level of risk. In general, the contribution of the source category to elevated facilitywide cancer or noncancer risks is low throughout the facilities in this source category. The primary processes driving the facilitywide cancer and noncancer risks are welding and blasting which are not regulated under this source activity.

Comment: A commenter stated that the EPA has determined that maximum individual cancer risk at the facilitywide level is 200-in-1 million based on estimated "actual" emissions. This means that the risk is likely to be higher based on allowable emissions. Further, of the 41 facilities with facilitywide MIR of 1-in-1 million or more, 15 have shipbuilding and ship repair operations that contribute over 50 percent to the facilitywide risks. Yet, the EPA does not propose to take any action to address that risk. The EPA should investigate ways to reduce this residual risk. It does not consider or address whether this level of facilitywide risk is acceptable at facilities where this source category is contributing so significantly. The EPA must do so to complete its CAA section 112(f)(2) duty. Its failure to consider regulatory options to address this residual risk is also arbitrary and capricious. At minimum, the EPA should consider whether to set a residual risk standard in order to reduce this high level of facilitywide risk. It should consider requiring extra work practice, reporting, monitoring and other measures for facilities that have the level of emissions putting them into this highest risk category. In sum, the EPA must address what standard is needed "to provide maximum feasible protection against risks to health" by "protecting the greatest number of persons possible" to a lifetime risk level no greater than 1-in-1 million. (quoting Benzene NESHAP), and its facilitywide risk analysis has failed to complete this essential step.

Response: We examined facilitywide risk to provide additional context to the source category risks. Facilitywide risks are driven by estimated emissions from blasting and welding sources at shipbuilding and ship repair facilities. These sources are not part of the Shipbuilding and Ship Repair (surface coating) source category. As discussed in the preamble to the proposed actions for this source category [75 FR 80237], we intend to list welding and blasting operations as a major source category under section 112(c)(5) of the CAA.

Comment: A commenter stated that with respect to the Shipbuilding and Ship Repair standard, we are concerned that the EPA based its decision that no additional controls are needed and that the existing standard provides an ample margin of safety in part due to "the uncertainty and lack of data associated with one potential risk reduction option identified, and the technological infeasibility of the other option identified." The commenter urged the EPA to obtain the necessary data regarding the two options to make a more informed decision, including contacting air quality agencies that currently regulate the source category. We compliment the EPA on its intention to list welding and blasting operations at shipbuilding and ship repair facilities as a major source category under section 112(c)(5), but encourage the EPA to determine the extent to which this action will address the risks remaining at these facilities before deciding that relying on this strategy is sufficient.

Another commenter stated that the EPA's proposal fails to satisfy the "ample margin" requirement. The EPA bases this conclusion in part on the fact that it has "not identified any data regarding the availability, use, performance and emissions associated with the use of lower overall volatile organic hazardous air pollutants (VOHAP) content or lower toxicity VOHAP content." *Id.* The EPA's conclusion is incorrect based on the use of the California standards in place. It is unclear why the EPA did not simply contact the four identified California air quality districts that have more stringent emission limits to attempt to gather these data. See Part IV.A.1, *infra.* This is the 8-year residual risk rulemaking and now is the time to collect and consider those data. The EPA may not defer or ignore this responsibility, or the fact that stricter standards are in use that it must address. The EPA also cannot justify a failure to set a residual risk standard on a lack of data. The EPA has failed to explain how the existing section 112(d) standard could provide the required "ample margin of safety." One commenter also stated that where other jurisdictions have implemented stronger standards, this provides evidence that for the purposes of CAA section 112(d)(6), that more stringent limitations are achievable and have been achieved.

However, the EPA states that there are differences between coating limits in the four air districts, and that the 1995 MACT standard includes cold weather limits which are not present in the California standards due to its moderate climate. Neither of these points is a valid reason for the EPA not to further analyze and adopt stronger standards based on these California examples. While it may not be appropriate to adopt the California standards in full on a national basis, the EPA gives no rational justification for not analyzing how to take these models and use them to create an appropriate national standard under CAA section 112(d)(6). The EPA concludes that "we do not have data to determine whether these lower-VOC content coatings could be applied nationwide." Gathering and analyzing that data, starting with any information already compiled by the California districts, is precisely what the section 112(d)(6) rulemaking is designed for. A lack of data is not a lawful basis for the EPA to decline to adopt a stronger MACT standard.

Response: The EPA researched current technologies for the shipbuilding and ship repair surface coating industry, and did not find any cost effective options that would make the current standard more stringent. Related to the marine coating limits in the MACT rule, we reviewed the general use and 22 specialty coating VOHAP limits and the lower limits that some states and air districts have adopted over the past decade for some of the specialty categories. Furthermore, we requested comment on the availability

and feasibility of using lower VOHAP coatings but did not receive any data or information during the comment period. Following proposal, we did contact a shipyard in Maine, and found that the use of lower VOHAP coatings, such as those required to meet the limits set by some of the California air quality districts, is not feasible in climates that are not as moderate and, therefore, necessitate greater thinning of paint.

As noted by the commenter, some jurisdictions have implemented more stringent standards that have resulted in changes to formulations being used in those locations. However, temperature and humidity issues experienced by other locations would make painting operations having to comply with the more stringent limitations more difficult, more expensive, and in some cases unachievable.

There are many different coatings, and in some cases groups of specific coatings, comprising each of the marine coating categories. Over the past several years, there have been changes to some formulations with HAP solvent reductions and solvent replacements, but those are coating and manufacturer specific and not reflective of the entire marine coating category.[33]

Comment: A commenter stated the EPA recognizes that there are "disparities in risks" for certain minority and lower-income individuals. For shipbuilding and ship repair, African Americans and people below the poverty level face a cancer risk of at least 1-in-1 million at a higher rate than their representation in the population. The EPA must consider potential ways to address the disproportionate impact on minority individuals and communities in deciding whether the likelihood of cancer risk is "acceptable" and whether there is action that could provide an "ample margin of safety" for these individuals and communities. Indeed, the EPA has recognized this since the development of the Benzene NESHAP, although it has failed to take action to address this (citing Benzene NESHAP factors, including "overall incidence of cancer or other serious health effects within the exposed population... other quantified or unquantified health effects"). These additional factors are supposed to be used in addition to the MIR. It is neither acceptable, nor just, to avoid the need to reduce the correlation between race or income level and a disproportionate risk of cancer from toxic air pollution. The EPA's proposals for inaction, in the face of the recognized disparities, contradict the Administrator's professed commitment to "fair treatment" (EJ Guidance, *infra* note 30, at 3). With the knowledge it has, the EPA must, at minimum, consider the amount of background pollution faced by, and baseline health of, racial minorities and communities affected by these two source categories, including for the types of health effects that these HAP emissions have potential to exacerbate. These types of health data are readily available for the EPA to factor into its analysis and to use in proposing a regulatory response to the disproportionate risk found. It would be arbitrary and capricious to propose to take no further action at all after finding these disparities for both source categories.

The commenter supports the EPA's effort to gather demographic data. Merely looking at these numbers in a simplistic manner, however, is no substitute for a true environmental justice (EJ) analysis. The EPA should develop and undertake an actual analysis of the location and community effects of these source categories. It has sufficient data on the locations of these facilities to undertake an analysis of the effect of their emissions on the maximum exposed individual, the history of pollution faced in the most affected community, and to consider how to set a just standard in view of these lasting harms.

Response: The demographic analysis found that African Americans and people below the poverty line may be somewhat disproportionately impacted by facilitywide air toxics emissions; however, emissions from the source category itself contribute minimally to these impacts. The EPA also found the overall level of risk from both source categories to be acceptable and to provide an ample margin of safety for all populations in close proximity to these sources. As noted previously, the EPA's ability to quantitatively assess impacts on EJ communities is evolving.

VI. Impacts of the Final Rules

We estimate the only compliance costs for these amendments to the Shipbuilding and Ship Repair (Surface Coating) MACT standard to be those costs associated with facilities that choose to take advantage of the affirmative defense although there is no expectation that a facility will have a need for affirmative defense in this source category. These estimated costs are $3,141 per year, and are discussed in section VII.B. For these amendments to the Wood Furniture Manufacturing Operations MACT standards, we estimate the compliance costs to be $188,000 per year for the formaldehyde limit reporting and recordkeeping provisions, and $3,141 for facilities that choose to take advantage of the affirmative defense although there is no expectation that a facility will have a need for affirmative defense in this source category. These costs are discussed in section VII.B.

VII. Statutory and Executive Order Reviews

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

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action." Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act (PRA)

The information collection requirements in the final rules have been submitted for approval to OMB under the PRA, 44 U.S.C. 3501, *et seq.* The information collection requirements are not enforceable until OMB approves them.

The information requirements are based on notification, recordkeeping and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

These final rules would require maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

When a malfunction occurs, sources must report them according to the

[33] See following memos to the docket on cost-effectiveness of control technologies: *Cost Analyses for Add-on Controls for Surface Coating Operations at Shipbuilding and Ship Repair Facilities*, dated September 2, 2010 and *Affordability of Add-on Controls for Shipbuilding and Ship Repair Source Category*, dated October 18, 2010.

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

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

In these source categories, compliance is primarily achieved through reformulation of the coating. Because of this a malfunction of equipment, other than control devices, will not result in an exceedance of the standard. As noted previously, there is a small percentage of wood furniture facilities that use control devices for compliance; malfunctions with these devices are unlikely due to limited number in the industry compounding the unlikelihood of a malfunction. Therefore, we assert that although a cost for affirmative defense is possible, we believe that malfunctions are unlikely. Thus for these source categories, the EPA is not assigning any burden associated with affirmative defense.

This burden estimate for Shipbuilding and Ship Repair (Surface Coating) has been assigned EPA ICR number 1712.07 and for Wood Furniture Manufacturing Operations has been assigned EPA ICR number 1716.08, and both have been updated to reflect the estimate cost of availing the affirmative defense should a facility choose this option.

For the Wood Furniture Manufacturing Operations MACT standards, the ICR document prepared by the EPA has also been amended to include burden changes associated with the amendments regarding the formaldehyde limit added to the rule. The change in respondents' annual reporting and recordkeeping burden associated with these amendments for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be 2,000 labor hours with a total cost of $188,000 per year for the formaldehyde limit reporting and recordkeeping provisions. There will be no capital costs associated with the information collection requirements of the final rule.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When these ICRs are approved by OMB, the agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control numbers for the approved information collection requirements contained in the final rules.

C. Regulatory Flexibility Act (RFA)

The 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 these final rules 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 these final rules on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The costs associated with the new requirements in these final rules (*i.e.*, the formaldehyde use limit and conventional spray gun prohibition in the Wood Furniture Manufacturing Operations standards) are negligible as discussed above.

D. Unfunded Mandates Reform Act (UMRA)

These rules do 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. Thus, these rules are not subject to the requirements of sections 202 or 205 of UMRA.

These rules also do not contain regulatory requirements that might significantly or uniquely affect small governments. They contain no requirements that apply to such governments or impose obligations upon them.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. These final rules primarily affect private industry and do not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to this action.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have a substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

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

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997), because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action will not relax the control measures on existing regulated sources, and the EPA's risk assessments (included in the docket for the proposed rules) demonstrate that the existing regulations are associated with an acceptable level of risk and an ample margin of safety to protect public health.

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

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. This action will not create any new requirements for sources in the energy supply, distribution or use sectors. Further, we have concluded that these final rules are not likely to have any adverse energy effects.

I. National Technology Transfer and Advancement Act (NTTAA)

Section 12(d) of the NTTAA of 1995, Public Law Number 104–113, 12(d) (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. The 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 the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable VCS.

This action does not involve technical standards. Therefore, the EPA did not consider the use of any VCS.

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

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

The EPA has determined that these final rules will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations, because we have concluded that the existing rules adequately protect human health with an adequate margin of safety and the final rules do not decrease the level of protection provided to human health or the environment. To examine the potential for any EJ issues that might be associated with each source category, we evaluated the distributions of HAP-related cancer risks across different social, demographic and economic groups within the populations living near the facilities where these source categories are located. Our analyses show that, for the two source categories evaluated, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic noncancer health impacts are unlikely. Our additional analysis of facilitywide risks showed that the maximum facilitywide cancer risks for all source categories are within the range of acceptable risks and that the maximum chronic noncancer risks are unlikely to cause health impacts. Although our additional analysis of the demographics of the exposed population shows some disparities in risks between demographic groups for both categories, the EPA has determined that no group is exposed to an unacceptable level of risk.

The rules will not relax the control measures on emissions sources regulated by the rules, and therefore, will not increase risks to any populations exposed to these emissions sources.

K. Congressional Review Act (CRA)

The CRA, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that, before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). The final rule will be effective on November 21, 2011.

List of Subjects for 40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: November 4, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, Title 40, chapter I, of the Code of Federal Regulations (CFR) is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

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

Subpart II—[Amended]

■ 2. Section 63.781 is amended by revising paragraph (d) to read as follows:

§ 63.781 Applicability.

* * * * *

(d) If you are authorized in accordance with 40 CFR 63.783(c) to use an add-on control system as an alternative means of limiting emissions from coating operations, in response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined in 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available in response to claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

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

(B) Could not have been prevented through careful planning, proper design

or better operation and maintenance practices; and

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

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

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

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

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

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

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

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

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

(2) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

■ 3. Section 63.782 is amended by adding a definition for "affirmative defense" to read as follows:

§ 63.782 Definitions.

* * * * *

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

* * * * *

■ 4. Section 63.783 is amended by redesignating paragraphs (b)(1) and (b)(2) as (b)(2) and (b)(3) and adding a new paragraph (b)(1) to read as follows:

§ 63.783 Standards.

* * * * *

(b) * * *

(1) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

* * * * *

■ 5. Section 63.785 is amended by adding paragraph (e) before Figure 1 to § 63.785 to read as follows:

§ 63.785 Compliance procedures.

* * * * *

(e) Continuous compliance requirements. You must demonstrate continuous compliance with the emissions standards and operating limits by using the performance test methods and procedures in § 63.786 for each affected source.

(1) General requirements.

(i) You must monitor and collect data, and provide a site specific monitoring plan, as required by §§ 63.783, 63.785, 63.786 and 63.787.

(ii) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), you must operate the monitoring system and collect data at all required intervals at all times the affected source is operating, and periods of malfunction. Any period for which data collection is required and the operation of the Continuous Emissions Monitoring System (CEMS) is not otherwise exempt and for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(iii) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. The owner or operator must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(2) [Reserved]

* * * * *

■ 6. Section 63.786 is amended by adding paragraph (e) to read as follows:

§ 63.786 Test methods and procedures.

* * * * *

(e) For add-on control systems approved for use in limiting emissions from coating operations pursuant to § 63.783(c), performance tests shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance of the affected source for the period being tested. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to demonstrate the conditions present during performance tests.

■ 7. Section 63.788 is amended by adding paragraph (b)(5) and revising paragraph (c) to read as follows:

§ 63.788 Recordkeeping and reporting requirements.

* * * * *

(b) * * *

(5) Each owner or operator that receives approval pursuant to § 63.783(c) to use an add-on control system to control coating emissions shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.*, process equipment) or the required air pollution control and monitoring equipment. Each owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.783(b)(1), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(c) *Reporting requirements.* Before the 60th day following completion of each 6 month period after the compliance date specified in § 63.784, each owner or operator of an affected source shall submit a report to the Administrator for each of the previous 6 months. The report shall include all of the information that must be retained pursuant to paragraphs (b)(2) through (3) of this section, except for that information specified in paragraphs (b)(2)(i) through (ii), (b)(2)(v), (b)(3)(i)(A), (b)(3)(ii)(A), and (b)(3)(iii)(A). If a violation at an affected source is detected, the owner or operator of the affected source shall also report the information specified in paragraph (b)(4) of this section for the reporting period during which the violation(s) occurred. To the extent possible, the report shall be organized according to the compliance procedure(s) followed each month by the affected source. If there was a malfunction during the reporting period, the report must also include the number, duration and a brief description of each malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.783(b)(1), including actions taken to correct a malfunction.

■ 8. Table 1 to subpart II of part 63 is amended by:

■ a. Removing entry 63.6(e)–(f);

■ b. Adding entries 63.6(e)(1)(i), 63.6(e)(1)(ii), 63.6(e)(1)(iii), 63.6(e)(2), 63.6(e)(3), 63.6(f)(1), and 63.6(f)(2)–(f)(3);

■ c. Removing entry 63.7;

■ d. Adding entries 63.7(a)–(d), 63.7(e)(1), and 63.7(e)(2)–(e)(4);

■ e. Revising entry 63.8;

■ f. Removing entry 63.10(a)–(b);

■ g. Adding entries 63.10(a), 63.10(b)(1), 63.10(b)(2)(i), 63.10(b)(2)(ii), 63.10(b)(2)(iii), 63.10(b)(2)(iv)–(b)(2)(v), 63.10(b)(2)(vi)–(b)(2)(xiv), and 63.10(b)(3);

■ h. Removing entry 63.10(c);

■ i. Adding entries 63.10(c)(1)–(9), 63.10(c)(10)–(11), 63.10(c)(12)–(14), and 63.10(c)(15);

■ j. Removing entry 63.10(d); and

■ k. Adding entries 63.10(d)(1)–(4) and 63.10(d)(5).

The revisions read as follows:

TABLE 1—TO SUBPART II OF PART 63—GENERAL PROVISIONS OF APPLICABILITY TO SUBPART II

Reference	Applies to subpart II	Comment
* * *	*	* * *
63.6(e)(1)(i)	No	See § 63.783(b)(1) for general duty requirement.
63.6(e)(1)(ii)	No.	
63.6(e)(1)(iii)	Yes.	
63.6(e)(2)	No	Section reserved.
63.6(e)(3)	No.	
63.6(f)(1)	No.	
63.6(f)(2)–(f)(3)	No	If an alternative means of limiting emissions (*e.g.*, an add-on control system) is used to comply with subpart II in accordance with § 63.783(c), then this section does apply.
* * *	*	* * *
63.7(a)–(d)	No	If an alternative means of limiting emissions (*e.g.*, an add-on control system) is used to comply with subpart II in accordance with § 63.783(c), then these sections do apply.
63.7(e)(1)	No	If an alternative means of limiting emissions (*e.g.*, an add-on control system) is used to comply with subpart II in accordance with § 63.783(c), then see § 63.786(e).
63.7(e)(2)–(e)(4)	No	If an alternative means of limiting emissions (*e.g.*, an add-on control system) is used to comply with subpart II in accordance with § 63.783(c), then these sections do apply.
* * *	*	* * *
63.8	No	If an alternative means of limiting emissions (*e.g.*, an add-on control system) is used to comply with subpart II in accordance with § 63.783(c), then this section does apply, with the exception of § 63.8(c)(1)(i), § 63.8(c)(1)(iii), and the last sentence of § 63.8(d)(3).
* * *	*	* * *
63.10(a)	Yes.	
63.10(b)(1)	Yes.	
63.10(b)(2)(i)	No.	

TABLE 1—TO SUBPART II OF PART 63—GENERAL PROVISIONS OF APPLICABILITY TO SUBPART II—Continued

Reference	Applies to subpart II	Comment
63.10(b)(2)(ii)	No	See § 63.788(b)(5) for recordkeeping of occurrence, duration, and actions taken during malfunctions.
63.10(b)(2)(iii)	Yes.	
63.10(b)(2)(iv)–(b)(2)(v)	No.	
63.10(b)(2)(vi)–(b)(2)(xiv)	Yes.	
63.10(b)(3)	Yes.	
63.10(c)(1)–(9)	No	If an alternative means of limiting emissions (*e.g.*, an add-on control system) is used to comply with subpart II in accordance with § 63.783(c), then these sections do apply.
63.10(c)(10)–(11)	No	If an alternative means of limiting emissions (*e.g.*, an add-on control system) is used to comply with subpart II in accordance with § 63.783(c), then see § 63.788(b)(5) for records of malfunctions.
63.10(c)(12)–(14)	No	If an alternative means of limiting emissions (*e.g.*, an add-on control system) is used to comply with subpart II in accordance with § 63.783(c), then these sections do apply.
63.10(c)(15)	No.	
63.10(d)(1)–(4)	Yes.	
63.10(d)(5)	No	See § 63.788(c) for reporting malfunctions.

* * * * * * *

■ 9. Table 3 to subpart II of part 63 is amended by revising entry "Determination of whether containers meet the standards described in § 63.783(b)(2)" to read as follows:

TABLE 3 TO SUBPART II OF PART 63—SUMMARY OF RECORDKEEPING AND REPORTING REQUIREMENTS [a] [b] [c]

Requirement	All Opts.		Option 1		Option 2		Option 3	
	Rec	Rep	Rec	Rep	Rec	Rep	Rec	Rep
* * * *	*			*			*	
Determination of whether containers meet the standards described in § 63.783(b)(3) ...	X	X	.....	.....	.....	.....	.....	.....
* * * *	*			*			*	

[a] Affected sources that comply with the cold-weather limits must record and report additional information, as specified in § 63.788(b)(3)(ii)(C), (iii)(C), and (iv)(D).

[b] Affected sources that detect a violation must record and report additional information, as specified in § 63.788(b)(4).

[c] OPTION 4: The recordkeeping and reporting requirements of Option 4 are identical to those of Options 1, 2, or 3, depending on whether and how thinners are used. However, when using Option 4, the term volatile organic hazardous air pollutants "VOHAP" shall be used in lieu of the term Volatile Organic Compounds "VOC," and the owner or operator shall record and report the Administrator-approved VOHAP test method or certification procedure.

* * * * *

Subpart JJ—[AMENDED]

■ 10. Section 63.800 is amended by:
■ a. Redesignating paragraphs (f) and (g) as paragraphs (h) and (i);
■ b. Redesignating paragraphs (d) and (e) as paragraphs (e) and (f);
■ c. Adding new paragraphs (d) and (g); and
■ d. Adding paragraph (j) to read as follows:

§ 63.800 Applicability.

* * * * *

(d) This subpart does not apply to any surface coating or coating operation that meets any of the criteria of paragraphs (d)(1) through (4) of this section.

(1) Surface coating of metal parts and products other than metal components of wood furniture that meets the applicability criteria for miscellaneous metal parts and products surface coating (subpart MMMM of this part).

(2) Surface coating of plastic parts and products other than plastic components of wood furniture that meets the applicability criteria for plastic parts and products surface coating (subpart PPPP of this part).

(3) Surface coating of wood building products that meets the applicability criteria for wood building products surface coating (subpart QQQQ of this part). The surface coating of millwork and trim associated with cabinet manufacturing are subject to subpart JJ.

(4) Surface coating of metal furniture that meets the applicability criteria for metal furniture surface coating (subpart RRRR of this part). Surface coating of metal components of wood furniture performed at a wood furniture or wood furniture component manufacturing facility are subject to subpart JJ.

* * * * *

(g) Existing affected sources shall be in compliance with § 63.802(a)(4) and § 63.803(h) no later than November 21, 2014. The owner or operator of an existing area source that increases its emissions of (or its potential to emit) hazardous air pollutants (HAP) such that the source becomes a major source that is subject to this subpart shall

comply with this subpart 1 year after becoming a major source.

* * * * *

(j) If the owner or operator, in accordance with 40 CFR 63.804, uses a control system as a means of limiting emissions, in response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined in 40 CFR 63.2. Appropriate penalties may be assessed, however, if the respondent fails to meet its burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, the owner or operator must timely meet the notification requirements in paragraph (j)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

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

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

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

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

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

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

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

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

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

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

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

(2) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (h)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

■ 11. Section 63.801 is amended by:

■ a. Adding a definition for "affirmative defense" and "low-formaldehyde" and revising the definition for "wood furniture" in paragraph (a); and

■ b. Adding paragraphs (b)(24) through (b)(28).

The additions and revisions read as follows:

§ 63.801 Definitions.

(a) * * *

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

* * * * *

Low-formaldehyde means, in the context of a coating or contact adhesive, a product concentration of less than or equal to 1.0 percent formaldehyde by weight, as described in a certified product data sheet for the material.

* * * * *

Wood furniture means any product made of wood, a wood product such as rattan or wicker, or an engineered wood product such as particleboard that is manufactured at any facility that is engaged, either in part or in whole, in the manufacture of wood furniture or wood furniture components, including, but not limited to, facilities under any of the following standard industrial classification codes: 2434, 2511, 2512, 2517, 2519, 2521, 2531, 2541, 2599, or 5712.

* * * * *

(b) * * *

(24) C_f = the formaldehyde content of a finishing material (c), in pounds of formaldehyde per gallon of coating (lb/gal).

(25) F_{total} = total formaldehyde emissions in each rolling 12 month period.

(26) G_f = the formaldehyde content of a contact adhesive (g), in pounds of formaldehyde per gallon of contact adhesive (lb/gal).

(27) V_c = the volume of formaldehyde-containing finishing material (c), in gal.

(28) V_g = the volume of formaldehyde-containing contact adhesive (g), in gal.

■ 12. Section 63.802 is amended by adding paragraphs (a)(4), (b)(4), and (c) to read as follows:

§ 63.802 Emission limits.

(a) * * *

(4) Limit formaldehyde emissions by complying with the provisions specified in either paragraph (a)(4)(i) or (a)(4)(ii) of this section.

(i) Limit total formaldehyde (F_{total}) use in coatings and contact adhesives to no more than 400 pounds per rolling 12 month period.

(ii) Use coatings and contact adhesives only if they are low-formaldehyde coatings and adhesives, in any wood furniture manufacturing operations.

(b) * * *

(4) Limit formaldehyde emissions by complying with the provisions specified in either paragraph (b)(4)(i) or (b)(4)(ii) of this section.

(i) Limit total formaldehyde (F_{total}) use in coatings and contact adhesives to no more than 400 pounds per rolling 12 month period.

(ii) Use coatings and contact adhesives only if they are low-formaldehyde coatings and adhesives, in any wood furniture manufacturing operations.

(c) At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

■ 13. Section 63.803 is amended by revising paragraph (h) to read as follows:

§ 63.803 Work practice standards.

* * * * *

(h) *Application equipment requirements.* Each owner or operator of an affected source shall not use conventional air spray guns except when all emissions from the finishing application station are routed to a functioning control device.

* * * * *

■ 14. Section 63.804 is amended by adding paragraphs (g)(9) and (h) to read as follows:

§ 63.804 Compliance procedures and monitoring requirements.

* * * * *

(g) * * *

(9) *Continuous compliance requirements.* You must demonstrate continuous compliance with the emissions standards and operating limits by using the performance test methods and procedures in § 63.805 for each affected source.

(i) *General requirements.* (A) You must monitor and collect data, and provide a site specific monitoring plan as required by §§ 63.804, 63.806 and 63.807.

(B) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), you must operate the monitoring system and collect data at all required intervals at all times the affected source is operating and periods of malfunction. Any period for which data collection is required and the operation of the CEMS is not otherwise exempt and for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(C) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. The owner or operator must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(ii) [Reserved]

(h) The owner or operator of an existing or new affected source subject to § 63.802(a)(4) or (b)(4) shall comply with those provisions by using either of the methods presented in § 63.804(h)(1) and (2) if complying with § 63.802(a)(4)(i) or (b)(4)(i) or by using the method presented in § 63.804(h)(3) if complying with § 63.802(a)(4)(ii) or (b)(4)(ii).

(1) Calculate total formaldehyde emissions from all finishing materials and contact adhesives used at the facility using Equation 5 and maintain a value of F_{total} no more than 400 pounds per rolling 12 month period.

$$F_{total} = (C_{f1}V_{c1} + C_{f2}V_{c2} + * * * + C_{fn}V_{cn} + G_{f1}V_{g1} + G_{f2}V_{g2} + * * * * + G_{fn}V_{gn}) \quad \text{Equation 5}$$

(2) Use a control system with an overall control efficiency (R) such that the calculated value of F_{total} in Equation 6 is no more than 400 pounds per rolling 12 month period.

$$F_{total} = (C_{f1}V_{c1} + C_{f2}V_{c2} + * * * + C_{fn}V_{cn} + G_{f1}V_{g1} + G_{f2}V_{g2} + * * * * + G_{fn}V_{gn}) * (1-R) \quad \text{Equation 6}$$

(3) Demonstrate compliance by use of coatings and contact adhesives only if they are low-formaldehyde coatings and contact adhesives maintaining a certified product data sheet for each coating and contact adhesive used, as required by § 63.806(b)(1), and submitting a compliance certification with the semiannual report required by § 63.807(c).

(i) The compliance certification shall state that low-formaldehyde coatings and contact adhesives, as applicable, have been used each day in the semiannual reporting period or should otherwise identify the periods of noncompliance and the reasons for noncompliance. An affected source is in violation of the standard whenever a coating or contact adhesive that is not low-formaldehyde, as demonstrated by records or by a sample of the coating or contact adhesive, is used. Use of a noncompliant coating or contact adhesive is a separate violation for each day the noncompliant coating or contact adhesive is used.

(ii) The compliance certification shall be signed by a responsible official of the company that owns or operates the affected source.

■ 15. Section 63.805 is amended by redesignating paragraph (a) as paragraph (a)(1) and adding paragraph (a)(2) to read as follows:

§ 63.805 Performance test methods.

(a)(1) * * *

(2) Performance tests shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance of the affected source for the period being tested. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

* * * * *

■ 16. Section 63.806 is amended by removing and reserving paragraph (e)(4) and adding paragraphs (b)(4) and (k) to read as follows:

§ 63.806 Recordkeeping requirements.

* * * * *

(b) * * *

(4) The formaldehyde content, in lb/gal, as applied, of each finishing material and contact adhesive subject to the emission limits in § 63.802(a)(4) or (b)(4) and chooses to comply with the 400 lb/yr limits on formaldehyde in § 63.802(a)(4) (i) or (b)(4)(i).

* * * * *

(k) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.*, process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.802(c), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

■ 17. Section 63.807 is amended by revising paragraphs (c) introductory text and (c)(3) and the first sentence in paragraph (d) to read as follows:

§ 63.807 Reporting requirements.

* * * * *

(c) The owner or operator of an affected source demonstrating compliance in accordance with § 63.804(g)(1), (2), (3), (5), (7), (8), (h)(1), and (h)(3) shall submit a report covering the previous 6 months of wood furniture manufacturing operations.

* * * * *

(3) The semiannual reports shall include the information required by § 63.804(g) (1), (2), (3), (5), (7), (8), (h)(1), and (h)(3), a statement of whether the affected source was in compliance or noncompliance, and, if the affected source was in noncompliance, the measures taken to bring the affected source into compliance. If there was a malfunction during the reporting period, the report shall also include the number, duration and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.802(c), including actions taken to correct a malfunction.

* * * * *

(d) The owner or operator of an affected source demonstrating compliance in accordance with § 63.804(g)(4), (6), and (h)(2) of this subpart shall submit the excess emissions and continuous monitoring system performance report and summary report required by § 63.10(e) of subpart A. * * *

* * * * *

■ 18. Table 1 to Subpart JJ of part 63 is amended by:

■ a. Removing entry 63.6(e)(1);

■ b. Adding entries 63.6(e)(1)(i), 63.6(e)(1)(ii), 63.6(e)(1)(iii);

■ c. Revising entries 63.6(e)(2) and (e)(3);

■ d. Removing entries 63.7 and 63.8;

■ e. Adding entries 63.7(a)–(d), 63.7(e)(1), 63.7(e)(2)–(e)(4), 63.8(a)–(b), 63.8(c)(1)(i), 63.8(c)(1)(ii), 63.8(c)(1)(iii), 63.8(c)(2)–(d)(2), 63.8(d)(3), and 63.8(e)–(g);

■ f. Removing entry 63.10(b)(2);

■ g. Adding entries 63.10(b)(2)(i), 63.10(b)(2)(ii), 63.10(b)(2)(iii), 63.10(b)(2)(iv)–(b)(2)(v), 63.10(b)(2)(vi)–(b)(2)(xiv);

■ h. Removing entry 63.10(c);

■ i. Adding entries 63.10(c)(1)–(9), 63.10(c)(10)–(11), 63.10(c)(12)–(c)(14), and 63.10(c)(15); and

■ j. Revising entry 63.10(d)(5) to read as follows:

TABLE 1 TO SUBPART JJ OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART JJ

Reference	Applies to subpart JJ	Comment
*	*	*
63.6(e)(1)(i)	No	See § 63.802(c) for general duty requirement.
63.6(e)(1)(ii)	No.	
63.6(e)(1)(iii)	Yes.	
63.6(e)(2)	No	Section reserved.
63.6(e)(3)	No.	
63.6(f)(1)	No.	
63.7(a)–(d)	Yes	Applies only to affected sources using a control device to comply with the rule.
63.7(e)(1)	No	See § 63.805(a)(1).
63.7(e)(2)–(e)(4)	Yes	Applies only to affected sources using a control device to comply with the rule.
63.8(a)–(b)	Yes	Applies only to affected sources using a control device to comply with the rule.
63.8(c)(1)(i)	No.	
63.8(c)(1)(ii)	Yes	Applies only to affected sources using a control device to comply with the rule.
63.8(c)(1)(iii)	No.	
63.8(c)(2)–(d)(2)	Yes	Applies only to affected sources using a control device to comply with the rule.
63.8(d)(3)	Yes, except for last sentence	Applies only to affected sources using a control device to comply with the rule.
63.8(e)–(g)	Yes	Applies only to affected sources using a control device to comply with the rule.

TABLE 1 TO SUBPART JJ OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART JJ—Continued

Reference	Applies to subpart JJ	Comment
* * *	*	* * *
63.10(b)(2)(i)	No.	
63.10(b)(2)(ii)	No	See § 63.806(k) for recordkeeping of occurrence and duration of malfunctions and recordkeeping of actions taken during malfunctions.
63.10(b)(2)(iii)	Yes	Applies only to affected sources using a control device to comply with the rule.
63.10(b)(2)(iv)–(b)(2)(v)	No.	
63.10(b)(2)(vi)–(b)(2)(xiv)	Yes	Applies only to affected sources using a control device to comply with the rule.
* * *	*	* * *
63.10(c)(1)–(9)	Yes.	
63.10(c)(10)–(11)	No	See § 63.806(k) for recordkeeping of malfunctions.
63.10(c)(12)–(14)	Yes.	
63.10(c)(15)	No.	
* * *	*	* * *
63.10(d)(5)	No	See § 63.807(c)(3) for reporting of malfunctions.
* * *	*	* * *

■ 19. Table 3 to Subpart JJ of part 63 is amended by adding an entry for "All Finishing Operations and Contact Adhesives" following the entry for "Contact Adhesives" to read as follows:

TABLE 3 TO SUBPART JJ OF PART 63—SUMMARY OF EMISSION LIMITS

Emission point	Existing source	New source
* * * *	*	*
All Finishing Operations and Contact Adhesives:		
(a) Achieve total free formaldehyde emissions across all finishing operations and contact adhesives, lb per rolling 12 month period, as applied	400	400
(b) Use coatings and contact adhesives only if they are low-formaldehyde coatings and contact adhesives	[f]1.0	[f]1.0
* * * *	*	*
* * * *	*	*

[f] The limits refer to the formaldehyde content by weight of the coating or contact adhesive, as specified on certified product data sheets.

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2004–0305; FRL–9491–2]

RIN 2060–AQ43

National Emission Standards for Hazardous Air Pollutant Emissions for Primary Lead Processing

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes the residual risk and technology review conducted for the Primary Lead Processing source category regulated under national emission standards for hazardous air pollutants (NESHAP). This action finalizes amendments to the NESHAP that include revision of the rule's title and applicability provision, revisions to the stack emission limits for lead, work practice standards to minimize fugitive dust emissions, and the modification and addition of testing and monitoring and related notification, recordkeeping, and reporting requirements. It also finalizes revisions to the regulatory provisions related to emissions during periods of startup, shutdown, and malfunction and makes minor non-substantive changes to the rule.

DATES: This final action is effective on November 15, 2011.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2004–0305. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information (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 *http://www.regulations.gov,* or in hard copy at the EPA Docket Center, EPA West Building, Room Number 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket and Information Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Mr. Nathan Topham, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; *telephone number:* (919) 541–0483; *fax number:* (919) 541–3207; and *email address: topham.nathan@epa.gov.* For additional contact information, see the following **SUPPLEMENTARY INFORMATION** section.

SUPPLEMENTARY INFORMATION: For specific information regarding the modeling methodology, contact Dr. Michael Stewart, Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Toxics Assessment Group (C504–06), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; *telephone number:* (919) 541–7524; *fax number:* (919) 541–0840; and *email address: stewart.michael@epa.gov.* For information about the applicability of this NESHAP to a particular entity, contact the appropriate person listed in Table 1 to this preamble.

TABLE 1—LIST OF EPA CONTACTS FOR THE NESHAP ADDRESSED IN THIS ACTION

NESHAP for:	OECA Contact [1]	OAQPS Contact [2]
Primary Lead Processing	Maria Malave, (202) 564–7027, *malave.maria@epa.gov.*	Nathan Topham, (919) 541–0483, *topham.nathan@epa.gov.*

[1] EPA's Office of Enforcement and Compliance Assurance.
[2] EPA's Office of Air Quality Planning and Standards.

Background Information Document. On February 17, 2011 (76 FR 9410), the EPA proposed revisions to the Primary Lead Smelting NESHAP based on evaluations performed by the EPA in order to conduct our risk and technology review. In this action, we are finalizing decisions and revisions for the rule. Some of the significant comments and our responses are summarized in this preamble; a summary of the other public comments on the proposal, and the EPA's responses to those comments, is available in Docket ID No. EPA–HQ–OAR–2004–0305. A red-line version of the regulatory language that incorporates the changes in this action is available in the docket.

Organization of This Document. The following outline is provided to aid in locating information in the preamble.

I. General Information
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K. Congressional Review Act

I. General Information

A. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action include:

TABLE 2—NESHAP AND INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

NESHAP and source category	NAICS[1] code	MACT[2] code
Primary Lead Processing	331419	0204

[1] North American Industry Classification System.
[2] Maximum Achievable Control Technology.

Table 2 is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by the final action for the source category listed. To determine whether your facility would be affected, you should examine the applicability criteria in the appropriate national emission standards for hazardous air pollutants (NESHAP). As defined in the source category listing report published by the EPA in 1992, the Primary Lead Smelting source category is defined as any facility engaged in producing lead metal from ore concentrates; including, but not limited to, the following smelting processes: Sintering, reduction, preliminary treatment, and refining operations.[1] To be consistent with the 1992 listing, the EPA is revising the applicability of the Primary Lead Smelting NESHAP to apply to any facility that produces lead metal from lead ore concentrates and is changing the title of the rule to reference Primary Lead Processing. For clarification purposes, all reference to lead emissions in this preamble means "lead compounds" (which is a hazardous air pollutant) and all reference to lead production means elemental lead (which is not a hazardous air pollutant) as provided under Clean Air Act (CAA) section 112(b)(7)).

If you have any questions regarding the applicability of any aspect of the Primary Lead Processing NESHAP, please contact the appropriate person listed in Table 1 of this preamble 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 will also be available on the World Wide Web (www) through the Technology Transfer Network (TTN). Following signature, a copy of the final action will be posted on the TTN's policy and guidance page for newly proposed and promulgated rules at the following address: *http://www.epa.gov/ttn/caaa/new.html.* The TTN provides information and technology exchange in various areas of air pollution control.

Additional information is available on the residual risk and technology review (RTR) web page at *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html.* This information includes source category descriptions and detailed emissions and other data that were used as inputs to the risk assessments.

C. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by January 17, 2012. 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 the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background

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

For MACT standards, the statute specifies certain minimum stringency requirements, which are referred to as floor requirements and may not be based on cost considerations. See CAA section 112(d)(3). For new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best controlled similar source. The MACT standards for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer

[1] USEPA. *Documentation for Developing the Initial Source Category List—Final Report,* USEPA/OAQPS, EPA–450/3–91–030, July, 1992.

than 30 sources). In developing MACT, we must also consider control options that are more stringent than the floor, under CAA section 112(d)(2). We may establish standards more stringent than the floor, based on the consideration of the cost of achieving the emissions reductions, any non-air quality health and environmental impacts, and energy requirements. In promulgating MACT standards, CAA section 112(d)(2) directs us to consider the application of measures, processes, methods, systems, or techniques that reduce the volume of or eliminate HAP emissions through process changes, substitution of materials, or other modifications; enclose systems or processes to eliminate emissions; collect, capture, or treat HAP when released from a process, stack, storage, or fugitive emissions point; and/or are design, equipment, work practice, or operational standards.

In the second stage of the regulatory process, we undertake two different analyses, as required by the CAA: section 112(d)(6) of the CAA calls for us to review these technology-based standards and to revise them "as necessary (taking into account developments in practices, processes, and control technologies)" no less frequently than every 8 years; and within 8 years after promulgation of the technology standards, CAA section 112(f) calls for us to evaluate the risk to public health remaining after application of the technology-based standards and to revise the standards, if necessary, to provide an ample margin of safety to protect public health or to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. In doing so, the EPA may adopt standards equal to existing MACT standards if the EPA determines that the existing standards are sufficiently protective. *NRDC* v. *EPA*, 529 F.3d 1077, 1083 (DC Cir. 2008).

On February 17, 2011, the EPA published a proposed rule in the **Federal Register** for the Primary Lead Smelting NESHAP, 40 CFR part 63 subpart TTT, that took into consideration the residual risk and technology review (RTR) analyses for that source category. This action provides the EPA's final determinations pursuant to the RTR provisions of CAA section 112 for the Primary Lead Processing source category. Specifically, as a result of our analyses, we are revising the requirements of the NESHAP to ensure public health and the environment are protected consistent with section 112(f) and that emission reductions are consistent with what is economically and technically feasible under section 112(d)(6). In addition, we are taking the following actions:

- Revising the requirements in the NESHAP related to emissions during periods of startup, shutdown, and malfunction (SSM).
- Revising the title of the rule and amending the applicability section consistent with the definition of the source category adopted in 1992, to provide that the NESHAP applies to any facility processing lead ore concentrate to produce lead metal.
- Replacing the definition of "primary lead smelter" with a definition of "primary lead processor" and adding definitions of "secondary lead smelters," "lead refiners," and "lead remelters."
- Incorporating the use of plain language into the rule.
- Addressing technical and editorial corrections in the rule.
- Responding to the January 2009 petition for rulemaking from the Natural Resources Defense Council (NRDC) that the original primary lead NESHAP should have included an emission standard for organic HAP and announcing our intention to collect additional data needed to develop a standard for organic HAP.

We note that the Doe Run Herculaneum Smelter, the only facility in the source category, is subject to a Consent Decree requiring submission of a facility-wide cleanup plan by January 1, 2013, shutdown of their sintering operations by the end of 2013, and shutdown of the blast furnace by April 30, 2014. The Consent Decree will achieve drastic reductions in emissions of lead and other pollutants and will provide substantial environmental and public health benefits. The Herculaneum area has also been designated as a nonattainment area for the 2008 National Ambient Air Quality Standards (NAAQS) for lead. Attainment of the 2008 Lead NAAQS (which is demonstrated based on three years of data at or below the level of the NAAQS) is required by December 2015. The State of Missouri is required to submit its attainment demonstration State Implementation Plan (SIP) by June 30, 2012.

III. Summary of the Final Rule

A. What are the final rule amendments for the Primary Lead Processing source category?

The National Emission Standards for Hazardous Air Pollutant Emissions: Primary Lead Smelting was promulgated on June 6, 1999 (64 FR 30204), and codified at 40 CFR part 63, subpart TTT. The primary lead processing industry consists of facilities that produce lead metal from ore concentrates. The source category covered by this MACT standard currently includes only one operating facility, The Doe Run Company in Herculaneum, Missouri.

For the reasons provided in the proposed rule and in the support documents in the docket, we have determined that the risks associated with this source category are unacceptable and are therefore promulgating requirements to reduce the risk to an acceptable level. Once risk is reduced to an acceptable level, we analyze whether there are additional controls that will provide an ample margin of safety, considering cost, energy, safety, and other relevant factors. We have concluded that there are no additional cost-effective controls available beyond those that we are requiring to reduce risk to an acceptable level and thus the same controls to ensure an acceptable level of risk will also provide an ample margin of safety. To satisfy section 112(f) of the CAA, we are, therefore, revising the existing MACT standard to include:

- An emission cap of 1.2 TPY for the furnace area stack and the refining operation stacks, combined.[2]
- Work practice standards to minimize fugitive dust emissions.

To satisfy section 112(d)(6) of the CAA, we are revising the existing MACT standard to include a reduction of the lead emission limit for the main stack. The MACT standard is being lowered from the current 1.0 pound per ton of lead produced to 0.97 pound of lead per ton of lead produced based on a determination that developments in practices, processes, or control technologies since promulgation of the MACT standards demonstrate that the facility can meet a reduced emission limit from the main stack pursuant to CAA section 112(d)(6).

In addition to our reviews under sections 112(f) and 112(d)(6) of the CAA, we are promulgating the following:

- The revision of the applicability section of the rule consistent with the definition of the source category adopted in 1992, subpart TTT which applies to any facility that produces lead metal from lead concentrate ore.
- Changes to the Primary Lead Processing MACT standards to

[2] EPA notes that it is setting a combined emission limit for these sources because, as noted in the proposal (76 FR 9432), and the risk assessment documents to support the proposed and final rulemakings, these sources have overlapping points of maximum lead impact.

eliminate the SSM exemption. These changes revise Table 1 in 40 CFR part 63, subpart TTT to indicate that several requirements of the 40 CFR part 63 General Provisions related to periods of SSM do not apply. We are adding provisions to the Primary Lead Processing MACT standards requiring sources to operate in a manner that minimizes emissions, removing the SSM plan requirement, clarifying the required conditions for performance tests, and revising the SSM-associated recordkeeping and reporting requirements to require reporting and recordkeeping for periods of malfunction. We are also adding provisions to provide an affirmative defense against civil penalties for exceedances of emission standards caused by malfunctions, as well as criteria for establishing the affirmative defense.

• Replacement of the word "shall" with the word "must" in the regulatory text. We are also replacing "thru" with "through." We are replacing the definition of "primary lead smelter" with a definition of "primary lead processor" and adding definitions of "secondary lead smelters," "lead refiners," and "lead remelters."

These revisions to the Primary Lead Processing MACT standard are expected to result in emissions reductions in lead and other hazardous air pollutants and increased compliance costs to the industry. No economic impacts on small businesses are expected as a result of the revisions to the rule. We have determined that the one facility in this source category can meet the applicable emissions standards at all times, including periods of startup and shutdown, in compliance with the current MACT standards.

B. What are the requirements during periods of startup, shutdown, and malfunction?

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

We have eliminated the SSM exemption in this rule. Consistent with *Sierra Club* v. *EPA,* the EPA has established standards in this rule that apply at all times. We have also revised Table 1 (the General Provisions table) in several respects. For example, we have eliminated that incorporation of the General Provisions' requirement that the source develop an SSM plan. We have also eliminated or revised certain recordkeeping and reporting that related to the SSM exemption. The EPA has attempted to ensure that we have not included in the regulatory language any provisions that are inappropriate, unnecessary, or redundant in the absence of the SSM exemption.

In establishing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not established different standards for those periods. Information on periods of startup and shutdown in the industry indicate that emissions during these periods do not increase. Furthermore, all processes are controlled by either control devices or work practices, and these controls would not typically be affected by startup or shutdown. Also, compliance with the standards requires averaging of emissions over three-month periods, which accounts for the variability of emissions that may result during periods of startup and shutdown. Therefore, separate standards for periods of startup and shutdown are not being promulgated.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 63.2). The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. Under section 112, emission standards for new sources must be no less stringent than the level "achieved" by the best controlled similar source and for existing sources generally must be no less stringent than the average emission limitation "achieved" by the best performing 12 percent of sources in the category. There is nothing in section 112 that directs the Agency to consider malfunctions in determining the level "achieved" by the best performing or best controlled sources when setting emission standards. Moreover, while the EPA accounts for variability in setting emissions standards consistent with the section 112 caselaw, nothing in that caselaw requires the Agency to consider malfunctions as part of that analysis. Section 112 uses the concept of "best controlled" and "best performing" unit in defining the level of stringency that section 112 performance standards must meet. Applying the concept of "best controlled" or "best performing" to a unit that is malfunctioning presents significant difficulties, as malfunctions are sudden and unexpected events.

Further, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not "reasonably" foreseeable. *See, e.g., Sierra Club* v. *EPA,* 167 F.3d 658, 662 (DC Cir. 1999) (EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to "invest the resources to conduct the perfect study."). *See also, Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (DC Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation."). In addition, the goal of a best controlled or best performing source is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with section 112 and is a reasonable interpretation of the statute.

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good

faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). The EPA is therefore adding to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. See 40 CFR 63.1542 Primary Lead Processing (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.). We also have added other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 63.1551 Primary Lead Processing. (See 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *." The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 63.1543(i) and 63.1544(d), and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *." In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with Section 113 of the Clean Air Act (see also 40 CFR 22.27).

The EPA included an affirmative defense in the final rule in an attempt to balance a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that "limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis." 42 U.S.C. 7602(k) (defining "emission limitation and emission standard"). *See generally Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (DC Cir. 2008) Thus, the EPA is required to ensure that section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief. While "continuous" limitations, on the one hand, are required, there is also caselaw indicating that in many situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (DC Cir. 1973), the DC Circuit acknowledged that in setting standards under CAA section 111 "variant provisions" such as provisions allowing for upsets during startup, shutdown and equipment malfunction "appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force." See also, *Portland Cement Association* v. *Ruckelshaus, 486 F.2d 375* (DC Cir. 1973). Though intervening caselaw such as *Sierra Club* v. *EPA* and the CAA 1977 amendments undermine the relevance of these cases today, they support EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating "upsets beyond the control of the permit holder." *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). *But see, Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (DC Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission limitations are "continuous" as required by 42 U.S.C. section 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

C. What are the effective and compliance dates of the standards?

The revisions to the MACT standards being promulgated in this action are effective on November 15, 2011. For the MACT standards being addressed in this action, the compliance date for the revised SSM requirements is the effective date of the standards, November 15, 2011. The compliance date for the revised emission standard in section 16.1543(a) is January 17, 2012. The compliance date for the revised requirements in section 16.1544 is February 13, 2012. The compliance date for the new refining and furnace area stack emission limit is 2 years from the effective date of the standard, November 15, 2013.

IV. Summary of Significant Changes Since Proposal

A. Changes to the Risk Assessment Performed Under Section 112(f) of the Clean Air Act

As noted above, in February of 2011 EPA published the notice of proposed rulemaking: National Emission Standards for Hazardous Air Pollutants: Primary Lead Smelting. In the proposed rulemaking, EPA presented a number of options for additional controls on the primary lead smelting source category, which currently includes only one facility operating in the United States. In the proposed rule, EPA solicited comment on these options as well as on all the analyses and data the options were based upon, including the risk methods and results presented in the draft document: Draft Residual Risk

Assessment for the Primary Lead Smelting Source Category.

During the public comment period for the proposed rule, the one facility in the source category, The Doe Run Company, submitted substantially updated emissions, meteorological, facility boundary, as well as other relevant information bearing on the risk assessment (see docket number: EPA–HQ–OAR–2004–0305 for Doe Run's public comments). As a result, to support this final rulemaking EPA revised its analyses to reflect the information received during the public comment period for the proposed rule. Revised methods, model inputs, and risk results are presented in the report: "Residual Risk Assessment for the Primary Lead Smelting Source Category" which is available in the docket for this rulemaking. In addition, a discussion of the updated emissions information used in the final risk assessment can be found in the Technical Support Document for the final rule, which can also be found in the docket for this rulemaking.

Table 3 presents the results of the final baseline risk assessment, with respect to the risks due to lead emissions, broken down by emission point. In the baseline scenario, we estimate that approximately 1,550 people may be exposed to lead concentrations above the NAAQS. Results indicate that emissions from the refining stacks and furnace area stacks can likely result in exceedences of the NAAQS for lead beyond the fenceline of the facility.[3] These results also indicate that fugitive dust emissions could result in exposures approximately equal to the level of the NAAQS at the location of maximum impact. The results also indicate that emissions from the main stack do not likely result in exceedences of the NAAQS for lead beyond the fenceline of the facility because emissions are highly dispersed due to the height of the main stack.

TABLE 3—SUMMARY OF LEAD CONCENTRATIONS RELATIVE TO THE NAAQS BASED ON ESTIMATED ACTUAL 2009 EMISSIONS

Emission point	2009 Emissions (tpy)	Offsite impact[3]
Main stack[1]	68.3	0.9 times the NAAQS.
Refining stacks[2]	9.1	8 times the NAAQS.
Furnace area stack: (Controlled blast and drossing fugitives)	2.5	2 times the NAAQS.
Fugitive dust	1.0	1 times the NAAQS.

[1] Results presented for the main stack in this table consider the good engineering practice (GEP) stack height of 330 feet (as was done in the SIP and in modeling submitted by the Doe Run Company in its public comments on the proposed rulemaking). The actual height of the main stack is approximately 550 feet, and thus the impact would likely be lower had actual stack height been modeled.

[2] Emission sources controlled by baghouses 8 and 9 at the Doe Run facility.

[3] For a given emission point, the model receptor location with the highest modeled 3-month ambient lead concentration was determined. This highest 3-month ambient lead concentration was then divided by the NAAQS (0.15 $\mu g/m^3$) for lead to determine the maximum offsite impact for a given emission point.

Consistent with the risk assessment to support the proposed rulemaking, the risk assessment to support the final rulemaking also indicates that risks are unacceptable. This decision considers all the risk estimates presented in the risk assessment document, but is primarily based on lead emissions from the furnace area stack and the refining operations stacks. We note that while the risk assessment supporting the proposed rulemaking estimated that a combined emission limit for the furnace area and refining operations should be set at 0.91 tons of lead per year to ensure that risks are acceptable, the updated risk assessment estimates that a combined emission limit of 1.2 tons of lead per year will ensure that ambient lead concentrations from those emission points do not result in lead levels in the ambient air above the level of the NAAQS for lead, thereby resulting in acceptable lead risk. In our ample margin of safety analysis, we identified no cost-effective controls that are capable of achieving emission levels below 1.2 tons per year, as described in the technical support document. Thus, the EPA is promulgating a combined lead emission limit for the furnace area and refining operations stacks at 1.2 tons per year.[4] In addition, the risk assessment projected ambient lead concentrations from fugitive dust emissions to be very close to the NAAQS for lead at the location of maximum impact; thus with respect to fugitive dust emissions, since only minimal (if any) reductions beyond those already in place are needed to ensure lead levels in the air do not exceed the NAAQS, the EPA believes that the work practice standards being promulgated in this rule, which are more stringent than currently required by the 1999 NESHAP, will ensure an acceptable level of risk.

Moreover, since this NESHAP includes work practice standards to minimize fugitive dust emissions, and since ambient monitoring for lead is already conducted very close to this facility and in the local community to demonstrate whether the area is attaining the lead NAAQS, we have decided that fenceline monitoring to specifically demonstrate that the source has adopted sufficient work practice standards to ensure fugitive emissions do not cause exceedances of the NAAQS is not necessary.

In addition to the updated lead risk assessment results presented above, we also note that there were changes to our cancer, acute, and PB–HAP multipathway screening analyses for non-lead HAP as a result of the new risk analysis performed for the final rule. With respect to our updated cancer risk assessment, we estimate that the maximum individual risk (MIR) of cancer is 20 in a million (as compared to 30 in a million based on the risk assessment to support the proposed rule), and that the cancer incidence is 0.008, or 1 excess cancer case every 125 years (as compared to 0.0008 based on the risk assessment to support the proposed rule). In addition, the refined worst-case acute hazard quotient (HQ) value is 2.0 (based on the REL for arsenic), driven by arsenic emissions from the main stack (as compared to 0.6 based on the REL for arsenic and driven by arsenic fugitive dust emissions as indicated by the risk assessment to

[3] For the reasons noted in the proposed rulemaking, 76 FR at 9421, we used the level of the lead NAAQS as the level above which we think an unacceptable risk is presented to the public.

[4] EPA notes that it is setting a combined emission limit for these sources because, as noted in the proposal (76 FR 9432), and the risk assessment documents to support the proposed and final rulemakings, these sources have overlapping points of maximum lead impact.

support the proposed rule). Finally, while the worst-case multipathway screen to support the proposed rule indicated that no non-lead PB–HAP exceeded screening levels for potential multipathway effects, in the risk assessment to support the final rulemaking, the worst-case multipathway screening level was exceeded with respect to cadmium emissions. This is the result of the revised emissions information provided by the company during the comment period, which indicated higher cadmium emissions from the main stack than were assumed for purposes of the risk assessment performed for the proposed rule.

In considering the updated non-lead risk results presented above, we note that while cancer incidence increased in our updated risk assessment, cancer incidence remains very low with 1 excess cancer case being estimated every 125 years.

With respect to the worst-case acute HQ value of 2 based on the REL for arsenic due to emissions from the main stack, we note that this is a conservative, worst-case analysis of the potential for acute health effects. We also note that in contrast to the risk analysis to support the proposed rulemaking, the final risk analysis modeled the main stack at the good engineering practice (GEP) stack height of 330 feet rather than the actual stack height of 550 feet. Thus it is very likely that the maximum potential worst-case HQ value is significantly lower than 2.

Finally, with respect to the exceedence of the worst-case multipathway screening level for cadmium, we note that this only indicates the potential for cadmium exposures above the chronic noncancer reference dose (RfD) for cadmium. That is, while in general, emission rates below the worst-case multipathway screening level indicate no significant potential for multipathway related health effects, emission levels above this worst-case screening level only indicate the potential for multipathway-related health risks of concern based on a worst-case scenario. We were not able to refine our multi-pathway analysis beyond the worst-case screening assessment. As a result, based on worst case screening, we cannot state whether or not there are going to be multipathway risks at true exposure levels, we can only say that worst case modeling suggests there could be potential risks. However, due to the highly conservative nature of this screening assessment and the uncertainties related to the results, we have concluded that, after implementation of the controls required by this rule, risks will be acceptable, considering the combination of potential multipathway risks, cancer risks, chronic non-cancer risks, and acute non-cancer risks. We also reviewed whether there were cost-effective controls that could further reduce risks as part of our ample margin of safety analysis. The controls we are requiring to address lead emissions also reduce emissions of non-lead HAP. We were unable to identify any technically feasible cost effective additional controls that would further reduce emissions of lead and non-lead HAP. We are therefore determining that the standards we are promulgating today provide an ample margin of safety to protect public health.

In summary, the final rule includes an emission standard of 1.2 tons per year of lead emissions from refining and furnace area stacks, combined. The standard also includes a requirement for the facility to employ work practice standards to minimize fugitive dust emissions, including cleaning plant roadways, stabilization of material during storage and handling, and ensuring that doorways to process areas remain closed. In summary, we conclude that these standards being promulgated today will ensure risks are acceptable and public health is protected with an ample margin of safety and that there will not be an adverse environmental effect from HAP emissions from the one lead processing facility in this source category.

B. Changes to the Technology Review Performed Under Section 112(d)(6) of the Clean Air Act

In the proposed rule, the main stack was subject to an emission limit of 0.22 pounds of lead per ton of lead produced based on our section 112(d)(6) technology review. That proposed limit was based on information that indicated the source had significantly lower emissions than the emission limit of 1 pound of lead per ton of lead produced (lb/ton) required in the 1999 MACT standard. However, in comments received on the proposed rule, The Doe Run Company indicated that the proposed emission limit of 0.22 lb/ton under Section 112(d)(6) could not be met and that the data on which that emission limit was based were not accurate. The facility provided a 2009 stack emissions test for the main stack that indicated that emissions at the facility are significantly higher than we assumed as the basis for the proposed limit. For purposes of our analysis for the final rule, the EPA recalculated the emissions performance achieved for the main stack as demonstrated by the 2009 and 2008 stack tests and considered an estimate of emission variability in order to determine whether it was appropriate to revise the emission limit based on what the source was able to achieve in practice. Based on the revised analysis, we are promulgating an emission limit for the main stack of 0.97 pounds of lead per ton of lead produced.

We have also changed the compliance date for the main stack to reflect compliance "as expeditiously as possible" under section 112(i)(3) of the CAA. The compliance date for the 0.97 lb/ton limit is 60 days from the date of publication of the final rule.

C. Other Changes Since Proposal

The EPA has decided not to include the refining and furnace area emissions as part of a facility wide emission limit as was proposed. We received comments from Doe Run on the proposed rule that inclusion of these sources in the production based emission limit in section 63.1543(a) was not necessary and that these sources would simultaneously be required to comply with the standard for refining and furnace area emissions proposed under section 112(f) and the production based limit proposed under section 112(d)(6). We agree with the commenters and we are establishing a separate emission limit of 1.2 tons per year of lead emissions that applies to the combined emissions of the refining and furnace area stacks. The emission standard limits the combined emissions from these two stacks because the revised risk assessment indicated that the location of maximum impact for these two stacks overlapped at the same receptor. A production based emission limit will continue to apply to sources in section 63.1543(a)(1)–(9).

As mentioned earlier, we are not finalizing a requirement for fenceline monitoring to ensure that fugitive dust emissions do not cause an exceedance of the NAAQS offsite. The revised modeling showed substantially lower ambient concentrations due to fugitive dust emissions relative to the modeling performed for the proposed rule. We estimate current fugitive dust emissions result in maximum lead levels offsite that are approximately equal to the NAAQS. We are promulgating work practice standards beyond what is required by the 1999 rule that must be implemented by the source in order to ensure that fugitive emissions will not result in an exceedance of the NAAQS and thus result in an unacceptable risk. We expect that after implementation of this revised NESHAP, fugitive dust emissions from primary lead processing

facilities will not result in exposures levels above the NAAQS. Since the risk levels are much lower than we had estimated at proposal, and since we are promulgating specific work practice requirements to minimize fugitive dust emissions, we have determined that the proposed fenceline monitoring requirement is not necessary to show compliance with this NESHAP. Furthermore, there are already several monitors nearby that measure ambient lead levels and that should provide sufficient indication of whether fugitive lead emissions have been sufficiently reduced.

In recent rules promulgated under section 112 and 129, the EPA has revised certain terms and conditions of the affirmative defense in response to concerns raised by various commenters. The EPA is adopting those same revisions in this rule. Specifically, the EPA is revising the affirmative defense language to delete "short" from 63.1551(a)(1)(i), because other criteria in the affirmative defense require that the source assure that the duration of the excess emissions "were minimized to the maximum extent practicable." The EPA is also deleting the term "severe" in the phrase "severe personal injury" in 63.1551(a)(4) because we do not think it is appropriate to make the affirmative defense available only when bypass was unavoidable to prevent severe personal injury. In addition, the EPA is revising 63.1551(a)(6) to add "consistent with good air pollution control practice for minimizing emissions." The EPA is also revising the language of 63.1551(a)(9) to clarify that the purpose of the root cause analysis is to determine, correct, and eliminate the primary cause of the malfunction. The root cause analysis itself does not necessarily require that the cause be determined, corrected or eliminated. However, in most cases, the EPA believes that a properly conducted root cause analysis will have such results. In addition, the EPA is revising 63.1551(b) to state that a written report must be submitted within 45 days of the initial occurrence of the malfunction and that the source may seek an extension of up to an additional 30 days.

V. Summary of Significant Comments and Responses

In the proposed action, we requested public comments on all aspects of the proposal, including our residual risk reviews and resulting proposed standards, our technology reviews and resulting proposed standard, and our proposed amendments to delete the startup and shutdown exemptions and the malfunction exemption and to establish an affirmative defense for malfunctions.

We received written comments from 16 commenters. Our responses to some of the significant public comments are provided below. Responses to the comments that are not in the preamble have been placed in the docket. See *Summary of Public Comments and Responses for Primary Lead Processing NESHAP* (October 2011), for summaries of other comments and our responses to them.

A. Timeline for Compliance

Comment: Two commenters opposed the compliance timing and supported extending the compliance date beyond two years for several reasons. One commenter stated that according to the time line in the proposed rule, the facility will operate in its current form for only a few months after the compliance date of the rule. This creates a dilemma for the State and facility in terms of implementation, planning, resources and compliance. The commenter suggested that the implementation and attainment schedules for this MACT rule should correspond to those of the 2008 NAAQS.

One commenter identified three provisions they suggest could be used to allow more than 2 years for compliance: (1) 112(i)(3)(A) establishes 3 years for compliance for section 112 standards, (2) 112(i)(5) allows exemption for up to 6 years for facilities demonstrating 90 percent reduction in HAP prior to first proposal of a section 112(d) standard, and (3) 112(h)(3) allows an alternative means of compliance in some circumstances. The commenter stated that the import of the underlying statutory authority relates to the compliance period for existing sources. Under the EPA practice, a three-year compliance period applies to section 112(d) MACT standards, while a two-year period applies to section 112(f) standards. Although the EPA seems to have reflexively applied the section 112(f) period, this approach is not foreordained in the present circumstances. Specifically, section 112(i)(3)(A), which allows a three-year compliance period for any section 112 standard, merits consideration in light of the various proposed MACT standards, including a plant-wide section 112(d)(6) standard. With regard to the authority under section 112(i)(5), the commenter states that emissions have been reduced from 140 tons in the year 2000 to less than 14 tons in 2009, representing a decrease of over 90%. With regard to section 112(h)(3), the commenter believes that the two year compliance period has serious adverse economic effects on the company and the new hydrometallurgical process can be considered an alternative means of emission limitation.

The commenter also stated that the circumstances of this case present a unique challenge in determining an appropriate compliance deadline for a new primary lead smelting MACT standard. The commenter stated that there were several differences from the typical MACT rulemaking: Instead of multiple sources within a category, there is only one facility in the category; by virtue of a federally enforceable consent decree, the facility must terminate its present operations by April 30, 2014; and assuming a final rule issues on October 31, 2011, and a two-year compliance deadline, the compliance period would be at most six months prior to stoppage of many of the current operations. If forced to achieve compliance that would last only for such a short period, the facility would face severe economic hardship that could jeopardize its ability to finance and to build a new hydrometallurgical lead production process that would largely eliminate lead emissions. These circumstances raise questions as to the legal necessity as well as the feasibility and practicality of implementing a two-year compliance deadline.

Further, it was incorrectly assumed that a two-year compliance period is consistent with the schedule of required actions contained in the Consent Decree, when the opposite is true. Requiring MACT standard compliance six months before the required termination of Doe Run's existing lead smelting seriously erodes several Consent *Decree goals:* Introducing a new hydrometallurgical lead production process that minimizes lead emissions, assuring continued primary lead production in the United States, and promoting the development of the most technologically advanced lead production process in the world.

Finally, the commenter stated that the primary lead RTR proposal effectively accelerates the compliance date for the lead NAAQS for the Doe Run facility. According to the commenter a two-year compliance timeframe relies, in part, on the various steps that must be undertaken to implement a plan to monitor lead concentration in air. But this reliance is also misplaced because it requires Doe Run to comply with the new Lead NAAQS in 2013, or more than two years before the Lead NAAQS itself requires compliance. No statutory authority supports such accelerated compliance for the lead NAAQS or preemption of the SIP process. In short,

the two-year timeframe rests on faulty grounds: Factually, it is inconsistent with the Consent Decree requirements, and legally, it unlawfully attempts to speed up the previously-established compliance timeframe for the lead NAAQS.

Response: Section 112(i)(3) establishes the compliance timeframe for any standard issued under section 112 for existing sources and provides that the compliance date shall be as expeditiously as practicable but no later than 3 years following the effective date of the standard. Section 112(f)(4), however, expressly provides more specific requirements for standards issued under section 112(f) and thus for section 112(f) standards those more prescriptive requirements govern in place of the compliance requirements in section 112(i)(3). Specifically, section 112(f)(4) provides that a source cannot emit an air pollutant in violation of a standard issued under subsection (f) except that the standard will not apply until 90 days after its effective date. It also provides that the Administrator may grant a waiver for a period of up to 2 years from the effective date if necessary for the installation of controls and if measures will be taken in the interim to ensure public health is protected from imminent endangerment. Thus, for standards applicable to the furnace and refinery area emissions and the work practice standards to address fugitive emissions, which were issued under section 112(f), the compliance period may not exceed two years from the effective date of the standard. We are providing 90 days for compliance with the work practice standards and two years for compliance with the standards applicable to the furnace and refinery area stacks.

The main stack emission limit, proposed under 112(d)(6), is subject to the section 112(i)(3) compliance provisions. We are establishing an emission standard of 0.97 lb Pb/ton of lead produced that would replace the existing standard of 1 lb Pb/ton of lead produced. This standard is based on the level of emissions that the source is already achieving in practice and thus no additional controls would be needed to meet that emission limit for the main stack. For that reason, we are requiring compliance with the new limit for the main stack within 60 days of the effective date of this final rule as this timeframe constitutes compliance "as expeditiously as practicable."

Concerning section 112(i)(5), the provision only applies to standards promulgated pursuant to section 112(d) (and not 112(f)) and also only where a source achieves a 90% reduction (95% in the case of HAPs that are particulate matter) prior to the proposal of the section 112(d) standard. Thus, this provision does not apply to the standards established under 112(f) in this final rule. With regard to the emission standard proposed for the main stack, stack test data indicate that the main stack emissions are substantially higher than the 14 tons per year value cited by the commenter. Based on performance test data, the facility has not achieved the reductions in emissions required to apply the alternative compliance dates in section 112(i)(5).

Section 112(h)(3) allows the Administrator through notice and comment rulemaking to accept an alternative means of emission limit in place of a work practice standard established under 112(h)(1) if the owner or operator of a source establishes that such alternative means will achieve reductions at least equivalent to those that would be achieved by the work practice standard. It is unclear precisely what the commenter is suggesting with regard to this provision. However, it seems they may be suggesting that the new hydrometallurgical process that they plan to install after they close the pyrometallurgical processes should be considered an alternative means of compliance with the work practice standard. It is unclear how this process would address the emissions covered by the work practice standards we are establishing which are intended to address current fugitive dust emissions from the facility. Those emissions are almost exclusively from lead entrenched in open areas and the installation of a new process for lead processing would not appear to affect those emissions. Moreover, we understand that the new hydrometallurgical process won't be operational until sometime after the compliance date for the work practice standards we are requiring. Thus, even if that process would address in whole or in part the fugitive dust emissions addressed through the work practice standards, it would not be an appropriate substitute in the absence of being able to achieve the necessary reductions within the compliance period. We note that our determination here does not preclude Doe Run from submitting additional information that may further support a demonstration under section 112(h)(3) and for which we could take further action in a separate rulemaking.

As to the concerns the commenter raises about this situation being unique, we do not disagree. However, the statute is clear that the maximum compliance period for standards issued pursuant to section 112(f) is two years. The commenter submits no facts or information that supports a legal basis for providing a longer period for compliance for the refining and furnace area stack limits and for the work practice standards to minimize fugitive dust emissions.

Finally, we note that the Lead NAAQS does not apply to a specific facility but rather is a level that must be met within the designated nonattainment area. However, we recognize that Doe Run is the only stationary industrial source creating the Jefferson County lead nonattainment area and the reductions required under the rule will help bring the area into attainment with the lead NAAQS. However, this regulation does not preempt the SIP process; the State of Missouri is still required to submit a state implementation plan demonstrating how the area will attain and maintain the lead NAAQS. In doing so, the State may rely on any reductions required under this regulation. Finally, we note that this regulation does not "speed up" the compliance timeframe for meeting the Lead NAAQS. The CAA requires areas to attain the various NAAQS as expeditiously as practicable, but no later than specified dates. For the 2008 lead NAAQS, areas are required to attain the standard as expeditiously as practicable, but no later than December 31, 2015. The Act not only contemplates but requires, if practicable, for areas to attain the 2008 lead NAAQS earlier than December 31, 2015.

Additionally, we are not requiring fenceline monitoring as part of the final NESHAP amendments. Therefore, the commenter's concerns related to potential conflict between monitoring for the NAAQS and this NESHAP are no longer relevant.

Comment: One commenter stated that the proposed emission standards and ambient standard had negative implications for determining compliance under the proposed two-year compliance period and the "plantwide reductions" that are "required under section 112(f)(2)." 76 FR at 9437/1. According to the commenter, the only plant-wide reduction proposed in the rule is the plant wide limit of 0.22 pounds per ton produced while the other two new numerical standards are the 0.91 tpy limit for furnace area and refining and casting operations and the 0.15 $\mu g/m^3$ limit for ambient lead concentrations.

The commenter stated that the three proposed numerical standards present a confusing regulatory regime as to which standard ultimately controls for determining compliance. If, for

example, Doe Run achieves an aggregate emission of 0.22 lb/ton on a facility wide basis but exceeds 0.91 tpy for its furnace and refining and casting operations, would it be in compliance?

Of the three numerical standards, the commenter stated that only the 0.91 tpy limit can arguably be linked to Section 112(f), and even that is unclear. The 0.91 tpy standard is derived from the Lead NAAQS risk analysis. Despite this starting point, this standard is subsumed in the proposed 0.22 lb/ton plant-wide limit which arose under the section 112(d)(6) technology review, adjusted for "variability in the operations and emissions." While an effort is made to differentiate the components of the 0.22 lb/ton standard as to which portion fits under what statutory authority, this single plant-wide emission standard rests on the section 112(d)(6) review. Although not explicitly stated, this plant-wide standard offers more than an ample margin of safety.

Response: We have decided not to include a facility-wide limit that would include the refining and furnace area stacks as well as to the main stack. Instead, the 1.2 tpy emissions standard we are promulgating under section 112(f) will apply to combined emissions from the refining and furnace area stacks. The 0.97 lb/ton emission standard that we are promulgating pursuant to section 112(d)(6) will replace the 1.0 lb/ton limit in the original MACT rule and will apply to the same sources subject to the limit in the original MACT rule. Additionally, we have eliminated the fenceline monitoring requirement from the final rule. These changes should alleviate the regulatory confusion that could arise over the limits in the proposal. Furthermore, we believe a plant-wide limit is not necessary to address the residual risk and technology review requirements of the Act. As provided in the preamble to the proposed and final rules, we evaluated each of the emission stacks separately to determine whether additional controls are necessary under section 112(f) or 112(d)(6) and a plant-wide limit is not needed under either of those statutory requirements.

B. The EPA's Authority Under Section 112 of the Clean Air Act

Comment: One commenter stated that the modification to the applicability provision does not comport with how smelting is defined and used and that the source category listing was intended to cover smelting only, not other processes. The commenter lists several issues supporting this position:

- The opening phrase of the first sentence "The Primary Lead Smelting source category," describes and limits "any facility" to mean those involving smelting; and the "includes, but is not limited to" language does not apply to any lead producing process, but only to "the following smelting processes."
- The list of processes identified all involve pyrometallurgical activities: Sintering process, blast furnace, electric smelting furnace, reverberatory furnace, slag fuming furnace, drossing kettles, and dross reverberatory furnace.
- The plain meaning of that language evidences intent to cover any and all types of pyrometallurgical processes for producing lead but shows no attempt to encompass other, as yet unknown, lead production processes.
- Isolating the phrase "including, not limited to" from the company it keeps to justify an expansive reading goes well beyond the meaning of the listing as a whole and thus cannot stand.

The commenter also stated that the proposed change in applicability is inconsistent with the statutory structure for formulating source categories: "To the extent practicable, the categories and subcategories listed under this subsection shall be consistent with the list of source categories established pursuant to section 7411 of this title and part C of this subchapter." The commenter cited several instances in the statute where Primary Lead Smelting is referred to as a pyrometallurgical process. In summation, the commenter states that the statutory directive of CAA section 112(c)(1) to assure consistency between a source category definition and how the same terms are used in other parts of the Act demonstrates that the statutory and regulatory use of "primary lead smelting" and "primary lead smelter" was consistently designed to cover only pyrometallurgical processes. The EPA's assertion that the originally formulated primary lead smelting source category has a "broader definition" is inconsistent with the original source category language and the pyro-oriented definitions applied to primary lead smelting/smelter found throughout the statute and regulations.

The commenter also stated that the EPA's effort to recast the primary lead smelting category is barred by the failure to show a major source would be present. The new hydrometallurgical process bears no resemblance to the current pyrometallurgical process, other than feedstock and end product. The new process will have drastically reduced lead emissions and is presented as a minor source in the Doe Run Air Construction Permit Application for the New Lead Technology submitted to the Missouri Department of Natural Resources.

Response: Section 112(c)(1) describes the process for creating the source category list. To the extent that the commenter is concerned that the source category listing for primary lead was not issued consistent with the requirements of section 112(c)(1), such claim is untimely. We disagree with the commenter that the source category description must be read to be limited to pyrometallurgical processes. The source category description was intended to include all processes used to produce lead metal from ore concentrates, as evidenced by the first sentence of the category description. While it is true that at the time of the source category listing, the hydrometallurgical process described by the commenter did not exist, the language left open the possibility that other lead metal production processes might be developed in the future and would be covered under the source category listing.

Although, the source category name in the 1999 NESHAP was "primary lead smelting" rather than "primary lead processing," it was given that title because, at that time smelting was the only technology used to process lead ore into lead metal. However, the three-word title should not be read as limiting the broader language in the description of the source category, which provides the full evidence of EPA's intent of what should be included in the source category.

Recently, during the development of this RTR rulemaking, we became aware of a new primary lead processing and production technology (*i.e.*, hydrometallurgical process). It is our understanding that even after this new technology is in place, the facility plans to continue operating some of the same thermal processes in use now and subject to the NESHAP (such as refining and casting) which continue to have the potential to emit significant amounts of lead. We also note that this facility will continue to have the potential for fugitive emissions. For these reasons, we conclude that it is appropriate and necessary to update the title for the MACT standard and the applicability section of the standard, consistent with the description of the listed source category, to ensure these emissions points continue to be subject to emissions standards. However, it is also important to note that the rule being promulgated today has no requirements that apply to the hydrometallurgical processes themselves, since this process currently does not exist at this facility.

As noted in the response to comments, if a new process such as the hydrometallurgical process is developed and put into use in the future, then EPA would consider what standards to propose for such process after such process is operational.

We believe section 112(d)(1) provides the authority for this revision to the standard. That provision requires EPA to "promulgate regulations establishing emission standards for each category or subcategory of major sources and area sources" of the hazardous air pollutants listed in section 112(b)(1). Because EPA's initial promulgation of the MACT standard did not fully describe the source category, and thus did not regulate all potential sources within the source category, we believe it is now appropriate to revise the applicability provision to fully cover the sources as provided under the source category listing.

Comment: A commenter stated that the proposed rule does not suggest that the new lead production processes should be listed as area sources. If the EPA could make the necessary "adverse effects finding" for including a hydrometallurgical lead production process as an area source, a separate NESHAP would be required for a new area source. The EPA lacks authority to subsume a new area source into the Primary Lead Smelting major source category, as it would require in the proposed rule. Therefore, the EPA must show that either Doe Run's new lead production process or the entire Doe Run facility after the new process is operational would or could emit more than 10 tpy of lead if the facility is to remain a major source category and the proposed rule offers no documented evidence that Doe Run's hydrometallurgical lead production process or the Herculaneum facility after the new process becomes operational would constitute a major source. The commenter contended that neither the new process nor the entire Herculaneum facility would be a major source. Plant-wide emissions at Doe Run's facility after the new process becomes operational are estimated to approximate 0.65 tpy. Absent the presence of a major source at Doe Run's facility, the new lead production process cannot be treated as a major source category.

Response: As explained in detail elsewhere, the EPA has the authority to impose additional requirements on emission points already subject to an emission standard and to impose requirements on previously unregulated emission points in performing a risk and technology review. The EPA has exercised that authority here by establishing emission limitations for activities previously only subject to work practice requirements. The commenter's arguments to the contrary notwithstanding, the revised applicability definition will result in a source category containing a major source, the Doe Run facility. Doe Run is currently a major source of lead emissions and will be a major source of such emissions on the date by which it must initially comply with the newly established emission limits for refining activities. Thus, regardless of the level of its emissions following conversion to the hydrometallurgical process, Doe Run must meet the newly established emission limits by the specified date(s). As noted elsewhere, a new hydrometallurgical process is not subject to an emission limit under the existing MACT standard as it now exists or following the changes resulting from this rulemaking; we would consider an appropriate emission limit for the hydrometallurgical process once that process is a demonstrated technology.

Comment: Another commenter stated that the EPA appropriately proposes to update the applicability of the MACT to cover Doe Run's new type of facility.

Response: We agree with this comment.

Comment: Two commenters stated that the EPA cannot use section 112(f) authority to establish an ambient air standard because this type of standard is not an "emission standard."

The commenters stated that the NAAQS does not fit within the meaning of "emission standard" as used in CAA sections 112(d)(6) or (f)(2), the EPA's stated authority for the proposed rule. Section 112(f)(2) is entitled "Emission standards" and the second sentence, where the "ample margin of safety" factor is found, has "emission standard" as its subject; these specific references clarify the use of "standards" elsewhere in the subsection means "emission standard." Likewise, section 112(d)(6) gives the Administrator authority to revise "emission standards." Both subsections limit the EPA's rule-promulgating authority to setting "emission standards."

According to commenters, Congress defined "emission standard" in CAA section 302(k) to "mean a requirement established by the * * * Administrator which limits the quantity, rate or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source * * * and any design, equipment, work practice or operational standard promulgated under this chapter." The language can only be reasonably read to allow a standard applicable to emissions from specific source(s). The lead (or any other) NAAQS, by definition, is not targeted to specific source(s), but applies generally to the national ambient air. See, *e.g.*, CAA section 109(a)(1)(A) ("regulations prescribing a national primary ambient air quality standard * * * for each air pollutant").

The commenters stated that the contrasting language highlights that the lead NAAQS does not qualify as an emission standard within the meaning of section 112. The NAAQS addresses ambient air rather than emissions from a source, and as a result the NAAQS does not put any limits on the quantity, rate, or concentration of emissions from a particular source or on its operation, maintenance, design, or work practices, all of which are central to the section 112(f)(2) mandate or on the practices, processes, and control technologies related to sources central to section 112(d)(6). Further, a NAAQS limits ambient air lead without regard to source category or types of sources, while the MACT standards are particularized to control emissions at specific sources. Thus, the primary lead smelting emission standards differ from the secondary lead smelting emission standards, but the same lead ambient air standards apply throughout the country without regard to such distinctions. In short, the lead NAAQS does not fit the meaning of "emission standard" as used in section 112 and therefore cannot be properly used as the MACT standard here.

One commenter stated further that this error is not cured by the wording of proposed section 63.1544(a), which states: "No owner * * * shall discharge or cause to be discharged into the atmosphere lead compounds that cause the concentration of lead in air to exceed 0.15 $\mu g/m^3$ on a 3-month rolling average measured at locations approved by the Administrator." As such, proposed section 63.1544(a) measures ambient air levels for compliance ("concentration of lead in air * * * at locations") in what appears to match the source monitoring of ambient air required for the Lead NAAQS. See 73 FR at 67052, section 50.16(a) and at 67059, section 58.10; see also 76 FR at 9436/1 (proposing that compliance "be demonstrated using a compliance monitoring system"). As such, proposed section 63.1544(a) does not limit the quantity, rate, or concentration of emissions from a specified source or take into account developments in practices, processes, and control technologies. Compare 40 CFR

63.1544(a)(2010) (requiring "manual that describes in detail the measures that will be put in place to control fugitive dust emissions from the sources"). Measuring ambient air at locations presumably near the source does not fall within the standards allowed by CAA section 112, and, in any event, is redundant to the same monitoring and limitations already established under the Lead NAAQS. Consequently, the proposed rule exceeds the statutory authority granted by section 112, and therefore cannot be adopted.

One commenter stated that the proposal requests comments on a work practices standard operating procedure (SOP) alternative to ambient air monitoring. As opposed to using the Lead NAAQS, which is not an emission standard under Section 112, the alternative SOP proposal is consistent with the MACT directive that emission reductions be tied to specific sources.

One commenter stated that the proposed ambient lead standard is procedurally flawed because the EPA fails to explain the legal basis for imposing such a standard under section 112(f). The agency's legal authority is of central relevance to this aspect of the proposal and the failure to clearly describe the legal basis for the standard violates the EPA's obligation under section 307(d)(3)(C) to set forth the "major legal interpretations" that underlie the proposal.

Response: The commenters mistake the purpose of the fenceline monitoring requirement in the proposed rule. The proposed rule established emissions standards from the main, furnace area, and refinery operations stacks and further provided that fugitive dust emissions would need to be addressed by work practice standards (as is allowed under section 112(h)(1)). Finally, we proposed a fenceline monitoring requirement to ensure that the work practice standards adequately address fugitive dust emissions consistent with the requirements of section 112(f). However, we have eliminated the fenceline monitoring requirement in the final rule. Instead, we are specifying work practice standards to minimize fugitive dust emissions. Because we are not requiring fenceline monitoring in this final rule, the commenter's concerns related to redundant monitoring requirements need not be addressed.

We disagree with the suggestion that we do not provide the legal basis for our proposed rule. The preamble clearly explains that we are addressing residual risk for this source category under section 112(f) and clearly explains the rationale for the proposed rule and the basis for the proposed requirements. (See 76 FR 9412–9414 for a discussion of the statutory authority underlying the proposed revisions to the standard.) With regard to fugitive dust emissions, we are establishing a requirement for work practice standards consistent with section 112(h)(1) in lieu of an emission standard because these fugitive dust emissions, which are predominantly from materials handling and roadways cannot be captured and vented to a stack for which we could establish an emission limit.

Comment: One commenter stated that the CAA limits the EPA's ability to regulate pollutants subject to NAAQS ("criteria pollutants") to that regime and does not allow supplemental (or supplanting) regulation of them under NESHAP. The commenter cited CAA section 112(b)(2) that states in relevant part: "No air pollutant which is listed under section 7408(a) of this title may be added to the list under this section" with certain exceptions not relevant here. Section 7408(a) provides the statutory authority for setting NAAQS. Also, CAA section 112(b)(7) removes elemental lead from consideration as a HAP. According to the commenter, the prohibition is not only clear, but also expansive: The statute "unqualifiedly prohibits listing a criteria pollutant as a HAP, that is, regardless of the reason." *Nat'l Lime Ass'n* v. *EPA*, 233 F.3d 625, 638 (DC Cir. 2000).

Response: As we recognized in the preamble to the proposed rule, under section 112(b)(7) elemental lead may not be listed as a HAP under section 112 and the references to "lead" in the proposed rule referred to "lead compounds" which are expressly listed as a HAP in CAA section 112(b)(1). 76 FR 9412. Because lead compounds are a listed HAP, we are required to regulate them under section 112, as we did when we established the original MACT standard for primary lead in 1999. 64 FR 30194. The lead emitted from primary lead processing is lead compounds with elemental lead present only in trace amounts.[5] The commenter did not provide any data to refute this. Thus, we disagree with the commenter that we are attempting to regulate in contravention of section 112(b)(7) in this action.

The *National Lime* opinion cited by the commenters addressed a different issue than the one being at issue here. In that case, the issue was whether the EPA could use a NAAQS pollutant (particulate matter) as a surrogate for HAP metal emissions. While certain HAP listed in 112(b)(1) are considered particulate matter, "particulate matter" is not listed on the 112(b)(1) list. In that case, the court rejected the argument by the National Lime Association that the EPA was regulating particulate matter "through the back door." In the present situation, the EPA is not regulating lead "through the back door" in this rulemaking.

Comment: One commenter stated that the EPA unlawfully refused to set a standard for organic HAP. According to the commenter, the EPA must set an emission standard for the organic HAP listed on the section 112(b)(1) list that this source category emits. Specifically, the commenter argues that:

> "[w]hen EPA performs a section 112(d)(6) review, it must consider the ongoing legality and effectiveness of the existing standard. Explicitly, in the current rulemaking EPA must "review, and revise as necessary" the existing MACT standard. 42 U.S.C. section 7412(d)(6). It is clearly "necessary" for EPA to close inherently unlawful gaps in the original MACT, by setting a standard for an uncontrolled HAP. Indeed, EPA has recognized the need and done this during its section 112(d)(6) review in its recent rulemaking for Marine Tank Vessel Loading Operations and Group I Polymers and Resins where it proposed a standard for previously uncontrolled subcategories of these sources. *See* Proposed Rule, 75 Fed. Reg. 65068, 65115, 65106 (Oct. 21, 2010). EPA has no legal basis for failing to set a MACT standard now for the uncontrolled HAPs for the primary lead source category."

Response: We disagree with the commenter that section 112(d)(6) mandates that the EPA must correct any deficiency in an underlying MACT standard when it conducts the "technology review" under that section. We believe that section 112 does not expressly address this issue, and the EPA has discretion in determining how to address a purported flaw in a promulgated standard. The "as necessary" language cited by the

[5] Harrison, R.M. and Williams, C.R. (1981). Environmental Science and Technology, Vol. 15:10, p. 1197–1204.; Ohmsen, G.S. (2001). Journal of the Air and Waste Management Association, Vol. 51, p. 1443–1451.; Uzu, G., Sobanska, S., Sarret, G., Sauvain, J.J., Pradère, P., and Dumat, C. (2011). Journal of Hazardous Materials, Vol. 186, p. 1018–1027.; Spear, T.M., Svee, W., Vincent, J.H., and Stanisich, N. (1998). Environmental Health Perspectives, Vol. 106:9, p. 565–571.; Czaplicka, M., and Buzek, Ł. (2011). Water, Air, & Soil Pollution, Vol. 218, p. 157–163.; Sobanska, S., Ricq, N., Laboudigue, A., Guillermo, R., Brémard, C., Laureyns, J., Merlin, J.C., Wignacourt, J.P. (1999). Environmental Science and Technology, Vol. 33, p. 1334–1339.; Harrison, R.M. and Williams, C.R. (1983). The Science of the Total Environment, Vol. 31, p. 129–140.; Batonneau, Y., Bremard, C., Gengembre, L., Laureyns, J., Maguer, A.L., Maguer, D.L., Perdrix, E., and Sobanska, S. (2004). Environmental Science and Technology, Vol. 38, p. 5281–5289.; Foster, R.L. and Lott, P.F. (1980). Environmental Science and Technology, Vol. 14:10, p. 1240–1244.

commenter must be read in the context of the provision, which focuses on the review of developments that have occurred since the time of the original promulgation of the MACT standard and thus should not be read as a mandate to correct flaws that existed at the time of the original promulgation. In several recent rulemakings, we have chosen to fix underlying defects in existing MACT standards under sections 112(d)(2) and (3), the provisions that directly govern the initial promulgation of MACT standards (see National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, October 28, 2009, 74 FR 55670; and National Emission Standards for Hazardous Air Pollutants: Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; and the Printing and Publishing Industry, April 21, 2011, 76 FR 22566). (We note that the commenter incorrectly states that we revised those standards under 112(d)(6)). We believe that our approach is reasonable because using those provisions ensures that the process and considerations are those associated with initially establishing a MACT standard, and it is reasonable to make corrections following the process that would have been followed if we had not made an error at the time of the original promulgation.

Nevertheless, based on our review of the commenter's 2009 petition and their additional comments on this proposed rulemaking, we agree that the Primary Lead Smelting NESHAP should have included an emission standard for organic HAP. We have evaluated available data and believe that we need additional data in order to set an emission standard for organic HAP that is representative of current operations and emissions. We intend to collect the needed data and propose a MACT emission standard under section 112(d)(2) and (3) of the CAA. Accordingly, we are not taking final action on the 2009 petition with respect to the issue of setting a standard or standards for organic HAP and will address that petition once we have gathered the necessary data.

C. Primary Lead Processing Risk Assessment

Comment: One commenter stated that the EPA failed to consider or account for cumulative risk and that there is no rational or scientific basis to dismiss consideration of the cumulative risk of exposures to HAPs due to uncertainties. The commenter urged that these uncertainties require protective action rather than inaction. The commenter stated that the EPA's Science Advisory Board (SAB) in May 2010 urged the EPA to use the RTR rulemaking process to do this as well as perform a sensitivity analysis to identify the major uncertainties in both the human health and ecological risk assessments. According to the commenter, the SAB and numerous other scientific experts have developed, and are in the process of developing, cutting edge methods to perform these assessments and that the EPA, as the lead environmental agency of the United States, has a responsibility to show leadership in this process. It should rely on the significant information already available and also use the current and future RTR rulemakings to further advance this process.

The commenter stated that it could be done on a site-specific basis or for the industry as a whole. Uncertainty in estimates of HAP in ambient air has been characterized, so the data available from the National-Scale Air Toxics Assessments (NATA) would allow a defensible estimate of what might be expected from other sources.

Response: We disagree with the commenter that our risk assessments do not consider cumulative risk. We note that our assessment of cancer risks is, in fact, cumulative, summing the risks associated with all carcinogens emitted by the facility. Similarly, the use of the target organ specific hazard index (TOSHI) for chronic non-cancer effects evaluates the cumulative effects of HAP on a given target organ. Further, our assessment for Primary Lead Processing is cumulative in that it considers all emission points within the fenceline (since they are all covered by the MACT). Moreover, the level of the lead NAAQS, which we used as the metric for defining unacceptable risk, was set based on all air-related exposures in its derivation and thus is also a cumulative standard. We note that for the present rulemaking, our consideration of cumulative risks for the Doe Run facility is the same as that for the industry as a whole since Doe Run is the only facility within the source category.

We further disagree with the commenter's assertion that a comprehensive quantitative assessment of risks from all sources outside the source category is required under the statute. If such were in fact the case, the task of completing such a requirement would take an interminable length of time. Instead, to provide the quantitative risk information necessary to inform RTR regulatory decisions, the EPA conducts a comprehensive assessment of the risks associated with exposure to the HAPs emitted by the source category (*i.e.*, those emissions that can actually be affected by the specific rulemaking) and supplements that with additional information about other possible concurrent and relevant risks that is readily available. In some cases, we have additional information about HAP emissions that are outside the scope of the particular rulemaking but within the boundaries of the subject facilities. In other cases, we may have ambient HAP monitoring data that can be considered as part of the regulatory decision-making. In still other cases, we may have very little additional risk information that can be considered. In all cases, however, when we consider additional information about risks, we also consider its attendant uncertainties, and information which carries significant uncertainties generally carries much less weight in the overall regulatory decision.

All of the quantitative risk assessment information about HAP emissions from the source category under consideration is also considered in the manner prescribed by the decision framework set forth by the CAA for residual risk decision-making (*i.e.*, the Benzene decision framework), and this means that the general guidelines of risk acceptability have been developed in a way that they already take into account the impossibility of accurately quantifying the health risks posed by outside forces on every individual in the population. They do this by noting that the guidelines apply in "the world in which we live," a world which is acknowledged to be "not risk-free," but rather a world which is full of risks, many of which can simply not be quantified. This acknowledgment allows the EPA to make risk-based decisions by focusing on the risks associated with the emissions that are themselves the subject of regulation being considered, and not get distracted by the daunting task of assessing all the other concurrent potential risks that may or may not be relevant and can't be impacted by the regulation in question anyway.

Comment: Two commenters took issue with the modeling methodology used for the RTR proposal and disagreed with the risk results based on a number of concerns.

One commenter stated that the RTR modeling characterized the maximum air lead concentrations near the facility to be fifty times the 2008 NAAQS which is inconsistent with both recent air quality monitoring data and Missouri's 2007 attainment demonstration modeling and stated that the proposed RTR modeling overestimated the maximum air lead concentration by at

least a factor of five. The commenter stated that the inaccuracies of the EPA's proposed modeling analysis will be in conflict with future baseline and attainment demonstration modeling based on more accurate data, especially since the RTR proposes to correlate the MACT standard with the 2008 NAAQS. The commenter recommended that the EPA remodel this facility using higher quality input data that are more representative of current operations at the Herculaneum facility, to obtain results that better reflect the actual monitored 3-month lead concentrations. Alternately, the commenter stated that the EPA should either defer to appropriate air quality monitoring information or to the modeling run used for the 2007 SIP revision attainment demonstration as the basis for this RTR. Some commenters also suggested using AERMOD modeling followed by LEADPOST, rather than using HEM–3 to ultimately calculate 3-month rolling average lead concentrations.

Two commenters identified specific issues with regard to the modeling approach and input data including:

- The ratio of modeled results to monitored data should not exceed a factor of two. The commenter provided specific corrections and analysis of data.
- The NAAQS attainment demonstration model developed by the State of Missouri and the RTR modeling, although conducted for different purposes, are both based on compliance with the same standard for the same geographic location. Therefore, the output of both dispersion models, whether for residual risk assessment or SIP development, should reflect the maximum ambient air lead concentration. The commenter stated that any data limitations should be addressed with input from the commenter.
- Improvements from the 2007 SIP for the fugitive emissions from the sinter plant and blast furnace building do not appear to be reflected in the run script of the model, resulting in concentrations up to fifty times the NAAQS. The commenter stated that actual monitoring data from 2010 show a maximum three-month average ambient air concentration of 1.12 μg/m^3 at the Main Street site. This actual monitored value is in line with the MDNR modeled estimate from the 2007 SIP revision and is recommended to be the basis for the risk assessment.
- The EPA did not provide a modeling protocol for their dispersion modeling, or all of the modeling inputs, post processing and other data in the docket for public review. Therefore, a complete, replicable public review of the model and assessment of the proposed RTR could not be made. The commenter identified several specific modeling parameters and data elements that were not correctly applied during the proposal modeling run which could have significantly affected the results including model control options, run script parameters, volume sources modeled as point sources, inaccurate fenceline/boundary locations, incorrect elevations for sources and receptors, and old census data information for receptor centroids.

Response: Because of the availability of newer emissions data, more detailed site-specific meteorological data, as well as updated facility boundary and other information provided by Doe Run in comments on the proposed rule, we have remodeled the facility with these newer data. We remodeled using AERMOD in the default mode to estimate monthly lead concentrations, and we used the building and particle data submitted by one commenter to model building downwash and plume depletion. We used the LEADPOST processor to calculate 3-month rolling averages. In addition, using the updated facility boundary information, the EPA also removed census blocks that would now be considered onsite. The methods and results of this modeling effort can be found in the document: Residual Risk Assessment for the Primary Lead Smelting Source Category, which is available in the docket for this rulemaking. The EPA notes that the results of this modeling effort are similar to results submitted by the Doe Run Company to the State as part of a SIP (this Doe Run modeling effort was also submitted to the EPA as part of its public comments). Moreover, the EPA notes that a comparison of modeled lead concentrations at the sites of six lead monitors are within 50 percent of measured concentrations at those monitors. These results are similar to a model-to-monitor comparison submitted by Doe Run in its public comments.

We note that the docket included all of the input files and documentation needed to reproduce the modeling that was performed for the proposal risk assessment.

Comment: With respect to using the NAAQS to evaluate potential multipathway risks from lead, one commenter stated that the risk assessment used to set the NAAQS was based on quantitative studies of young children and that while "the Lead NAAQS obviously applies to all ages, that was a qualitative risk management decision made as a matter of policy" and that "the task at hand is to provide a quantitative risk assessment of the maximum non-adverse facility-level emissions rate for all ages, which cannot be done on the basis of a risk assessment that studied children only.

Response: The lead NAAQS was a public health policy judgment considering the available health evidence and risk analyses as well as the uncertainties associated with the health evidence and risk analyses. We disagree with the commenter that the lead NAAQS cannot be used in a quantitative manner. The review of the lead NAAQS clearly resulted in a quantitative standard: 3-month maximum lead concentration not to exceed a level of 0.15 μg/m^3. This standard was set to protect public health, including the health of sensitive populations, with an adequate margin of safety. As the commenter notes, the lead NAAQS applies in all areas of the United States and is meant to protect the public health with an adequate margin of safety regardless of the age of the individuals living in a particular area.

Comment: One commenter stated that rather than finalizing this proposal as it stands, the best available science directs the EPA to set a residual risk standard that incorporates protective health benchmarks and assures that children living near the facility will not face an unacceptable neurological effect, such as the loss of IQ points. This includes protecting children against a blood lead level change of 1.0 μg/dL or more, a benchmark used by California for the blood lead level change that is associated with a child's loss of one IQ point. Because there is no safe level of lead exposure and because lead persists in the environment, resulting in reservoirs in soils and dusts, the EPA has an obligation to control emissions from this source category promptly and in a precautionary manner. The commenter stated that the EPA should consider requiring zero lead emissions. At a minimum, the EPA should set a standard that would ensure that the ambient air concentration for lead in the local community does not exceed the level of 0.02 μg/m^3 as a one-month average, in order to protect children. As this is the level the Children's Health Protection Advisory Committee had recommended for the lead NAAQS, the EPA must also set additional protections beyond this ambient air limit in order to provide an "ample margin of safety."

Response: In order to assess multipathway risks associated with emissions of lead, the EPA compared modeled rolling three month average lead concentrations estimated from emissions from the one source in this category to the NAAQS for lead. As

noted above, we believe that this is a reasonable approach given that the NAAQS is a health based standard set to protect the public health, including the health of sensitive sub-populations (such as children) with an adequate margin of safety. Moreover, the risk assessment supporting the NAAQS considered direct inhalation exposures and indirect air-related multi-pathway exposures from industrial sources like primary and secondary lead smelting operations. We conclude that the level of the NAAQS presents an acceptable level of risk from lead in ambient air. Moreover, we are promulgating emissions limits (for the furnace area and refining operation stacks) to reduce emissions and promulgating specific work practice standards to minimize fugitive emissions to ensure that emissions do not result in exceedances of the NAAQS. As part of our "ample margin of safety" analysis, we examined whether there were additional cost effective controls available to further reduce emissions and risks. As explained elsewhere in this notice and in other supporting documents available in the docket, we have not identified any additional cost effective controls to reduce emissions further and provide further risk reductions.

With respect to the California benchmark for protecting children, the EPA has a hierarchy of appropriate health benchmark values. In general, this hierarchy places greater weight on EPA derived health benchmarks than those from other agencies (*http://www.epa.gov/ttn/atw/nata1999/99pdfs/healtheffectsinfo.pdf*). For the reasons provided above, we believe that the lead NAAQS level establishes an appropriate benchmark for addressing the acceptable level of risk and we disagree with the commenter that we should instead use an ambient concentration of 0.02 $\mu g/m^3$ based on a one month average.[6]

Comment: With regard to the source category's emissions of two dozen other hazardous air pollutants, including cadmium and arsenic, one commenter stated that the EPA should determine that this health risk is also unacceptable. With thousands of people exposed to a lifetime risk of cancer above 1 in a million, and with at least 200 exposed to a lifetime risk of up to 30 in a million, the EPA must recognize that this risk is too high for this local community. The EPA should set a standard that would reduce cancer risks to an acceptable level and ensure an ample margin of safety from non-lead emissions.

Response: With respect to cancer risk, section 112 provides for EPA to follow the benzene decision framework for determining acceptability. Under that framework, cancer risk less than 100 in a million is generally considered acceptable, although this is not a bright line and EPA examines a variety of health factors to make its determination. Once we concluded that the risk from non-lead HAP was acceptable, we then considered whether there were additional cost-effective controls that would further reduce risk from the other HAP emitted in order to provide an ample margin of safety. Because the controls for other HAP were the same as the controls for lead, we determined (for the same reason we did for lead) that there were no additional cost effective controls and that the acceptable level of HAP emissions also provided an ample margin of safety.

Comment: One commenter stated that they oppose the use of the lead NAAQS assessment instead of a multi-pathway risk assessment because the lead NAAQS provides an inappropriate level of protection, *i.e.,* the lead NAAQS requires an adequate margin of safety while a residual risk standard requires an ample margin of safety. The commenter stated that a residual risk standard should provide a level of protection that is higher than the NAAQS. Moreover, the commenter noted that the NAAQS is set to protect sensitive populations while residual risk rules are set to protect the greatest number of individuals possible from unacceptable risk. The proposed rule based on the lead NAAQS will not provide as high a level of protection as required by CAA section 112(f)(2).

Response: We disagree with the commenter that the lead NAAQS assessment should not be considered as part of our residual risk analysis because it provides an inappropriate level of protection. The lead NAAQS is set at a level to protect public health, including the health of sensitive populations, most critical for lead, the health of children. That does not suggest that non-sensitive populations are not protected, but rather that the NAAQS is set at a level that will not only protect the general population but also those who are more sensitive to lead exposures. In the proposed rule, the level of the NAAQS, which protects public health with an adequate margin of safety, was used to determine whether or not there was unacceptable risk. Once we determined a level of emissions that results in risks being acceptable, under the two-step residual risk decision process, the EPA then considered whether there were additional controls that might further reduce risk to achieve an ample margin of safety considering cost and feasibility. We did not identify any additional cost-effective controls beyond those that would need to be implemented to ensure an acceptable level of risk. Thus, with regard to the two stack emissions points (the furnace area stack and the refinery stacks) for which we are requiring action to ensure an acceptable level of risk, and for fugitive dust emissions, for which we are specifying work practice standards, we have concluded that there are no additional cost-effective controls and that an ample margin of safety will be provided by the same controls that ensure an acceptable level of risk. Moreover, there are no additional cost effective controls to further reduce emissions from the main stack beyond those controls that are already applied. Therefore, an ample margin of safety will be provided by the current level of control for the main stack. A more detailed presentation of the economic analysis of additional controls for the refining, furnace area, and main stacks can be found in the technical support document, which is available in the docket.

Comment: One commenter stated that the EPA has not appropriately accounted for or prevented environmental risks from lead or non-lead emissions as required by section 112(f)(2)(A). According to the commenter, using the NAAQS to assess ecological risk is problematic and EPA's approach of assuming that "when exposure levels are not anticipated to adversely affect human health, they also are not anticipated to adversely affect the environment," 76 FR at 9425, is illogical and unlawful. Further, based on the information the EPA has gathered about the local environment around the Doe Run facility, the EPA cannot assume that there would be no effects either to wildlife or to natural resources in the environment either from inhalation or air deposition of HAP emissions, exacerbated by persistence and bioaccumulation. As the EPA's own Scientific Advisory Board has stated: "The assumption that ecological receptors will be protected if human health is protected is incorrect." SAB May 2010 at 48.

Response: The EPA is unaware of any data indicating a direct atmospheric impact of non-lead HAP emitted from this source category on receptors such as plants, birds, and wildlife. Given that there is no information supporting that

[6] This level is well below the background ambient lead levels measured in the area during the SIP process. See docket ID EPA–HQ–OAR–2006–0735–5204.

there is an effect, we find it appropriate to assume that exposure levels not expected to harm humans are also not expected to harm ecological receptors.

Although the ecological effects of lead are well documented, there was a lack of evidence at the time of the last lead NAAQS review linking various ecological effects to specific levels of lead in the air. It was determined that the evidence did not provide a sufficient basis for establishing a separate secondary standard, but that revising the secondary standard to be equal to the revised primary standard would provide substantial additional protection to ecological receptors from the effects of lead. Thus, we find it appropriate to consider the secondary lead NAAQS when evaluating the potential for adverse environmental effects.

Comment: One commenter generally stated that the EPA must not use the secondary NAAQS as a benchmark to determine whether there will be environmental effects and that the use of the lead NAAQS to evaluate ecologic risks is inappropriate. The commenter states that the EPA should recognize that the establishment of the Secondary lead NAAQS at the same level of the Primary Lead NAAQS was a risk management decision, rather than a decision quantitatively founded in risk assessment. The commenter cited that in establishing the lead NAAQS, the EPA introduced its approach by describing the "substantial limitations in the evidence, especially the lack of evidence linking various effects to specific levels of ambient Pb" (U.S. EPA, 2008. P. 67007), and ultimately concluded that the secondary lead NAAQS should be set equal to the primary lead NAAQS.

In contrast, in this proposed rule, the EPA concludes that "ambient lead concentrations above the lead NAAQS indicates potential for adverse environmental effects" (76 FR 9421).

Response: The secondary lead NAAQS was set to protect against adverse welfare effects (including adverse environmental effects) and has the same averaging time, form, and level as the primary standard. Thus, we find it appropriate to consider the secondary lead NAAQS when considering the potential for adverse environmental effects. The commenter is correct that we stated in the proposed rule that "ambient lead concentrations above the lead NAAQS indicates potential for adverse environmental effects." This statement is entirely consistent with the idea that the secondary lead NAAQS was set at a level above which there may be adverse environmental effects but does not support a conclusion that there are adverse environmental effects below that level that must be addressed as part of this residual risk determination. As we have noted previously, there are not sufficient data supporting that a lower level is necessary to protect against an environmental risk.

Comment: One commenter stated that in evaluating potential multipathway risks from PB–HAP other than lead, the EPA used *de minimis* emission rates to screen for potentially significant multi-pathway impacts, but for lead, this method was abandoned. The commenter disagrees with this approach, stating, "This comparison mirrors NAAQS source monitoring for attainment purposes in its use of the national ambient air lead level as the benchmark. As such, it is not a proper surrogate for "facility-level *de minimis* emission rates" used as the chronic reference benchmarks for CAA section 112 risk assessments."

Response: The EPA disagrees that comparing modeled 3-month rolling average lead concentrations to the NAAQS for lead mirrors source monitoring for NAAQS attainment purposes and that this approach is not a proper surrogate for facility-level *de minimis* emission rates used as the chronic reference benchmarks for CAA section 112 risk assessments. In general, determining attainment for the lead NAAQS is based on aggregate ambient monitoring of all potential sources of lead in a given area. In contrast, the Primary Lead Smelting Risk Assessment and Preamble clearly state that 3-month rolling average lead concentrations are based on modeled lead concentrations from lead emissions from the one facility in the source category. 76 FR 9421. Thus, for example, while for NAAQS attainment purposes ambient lead concentrations resulting from lead haul roads outside the facility boundary would contribute to the overall 3-month rolling average ambient lead concentration measured at a nearby ambient lead monitor, for purposes of the risk assessment to support this rulemaking, these types of offsite emission sources were not included when modeling 3-month rolling lead concentrations (*i.e.*, only emission sources from within the facility boundary were used as inputs into the dispersion model to estimate resulting modeled 3-month average lead concentrations).

The NAAQS for lead was set to protect, with an adequate margin of safety, human health, including the health of children and other at-risk populations, against an array of adverse health effects, most notably including neurological effects, particularly neurobehavioral and neurocognitive effects, in children (73 FR 67007). In developing the NAAQS for lead, because of the multi-pathway, multi-media impacts of lead, the risk assessment supporting the NAAQS considered direct inhalation exposures and indirect air-related multi-pathway exposures from industrial sources like primary and secondary lead smelting operations. It also considered background lead exposures from other sources (like contaminated drinking water and exposure to lead-based paints). The EPA believes that the lead NAAQS is a reasonable benchmark to evaluate the potential for multipathway health effects from lead.

Finally, as noted in the risk assessment document, there is no RfD or other comparable chronic health benchmark value for lead compounds. That is, in 1988, the EPA's IRIS program reviewed the health effects data regarding lead and its inorganic compounds and determined that it would be inappropriate to develop an RfD for these compounds, saying, "A great deal of information on the health effects of lead has been obtained through decades of medical observation and scientific research. This information has been assessed in the development of air and water quality criteria by the Agency's Office of Health and Environmental Assessment (OHEA) in support of regulatory decision-making by the Office of Air Quality Planning and Standards (OAQPS) and by the Office of Drinking Water (ODW). By comparison to most other environmental toxicants, the degree of uncertainty about the health effects of lead is quite low. It appears that some of these effects, particularly changes in the levels of certain blood enzymes and in aspects of children's neurobehavioral development, may occur at blood lead levels so low as to be essentially without a threshold. The agency's RfD Work Group discussed inorganic lead (and lead compounds) at two meetings (07/08/1985 and 07/22/1985) and considered it inappropriate to develop an RfD for inorganic lead." The EPA's IRIS assessment for Lead and compounds (inorganic) (CASRN 7439–92–1), *http://www.epa.gov/iris/subst/0277.htm.*

Comment: One commenter stated that the EPA must include a plain language statement of health risks and benefits of the proposed rule. As part of its rulemaking proposal, the EPA should include a plain statement of the health impacts and risks at issue. For example, the commenter stated that the MIR and chronic and risk numbers are not easily

understandable by the general public; the IQ point losses at stake or how it is setting a standard to address these are not discussed, and the types of cancer or the nature of the health disorders or other adverse effects that most of these types of HAP emissions present to the public are not discussed. The commenter stated that this type of "[e]xpanded discussion is important to understanding the 'real-world' risk, including dealing with health disparities." SAB May 2010 at 50.

A full elaboration of the types of health impacts at issue here, ranging from significant IQ loss (due to lead emissions), to a high lifetime cancer risk (from non-lead emissions), for this particular community, is needed to inform the EPA's and the public's consideration of what level of risk is acceptable or unacceptable, and what standard is required to provide an ample margin of safety.

Response: The EPA strives to communicate its health and risk information to the public in a manner that is concise, informative, and readily understandable. In the risk assessment document, we discuss the various metrics used to characterize risk associated with the source category (*e.g.*, see section 2.3 of the risk assessment document for a discussion of the MIR). Moreover, while the commenter is correct that we do not discuss in detail the neurological effects associated with exposure to lead (*e.g.*, loss of IQ points in children), we do reference the final lead NAAQS decision, which does discuss in detail the health effects associated with lead exposure. With regard to how the proposed controls limit the health risks associated with lead exposure, we noted in the preamble of the proposed rule that the proposed controls would ensure that the facility's contribution to ambient concentrations of lead were at or below the NAAQS for lead and that this represents an acceptable level of risk since the lead NAAQS was set to protect public health, including the health of sensitive populations (*e.g.*, children), from the adverse health effects associated with lead exposure. Moreover, although the requirements that we are promulgating in today's action are somewhat different than the proposed requirements, we believe that the requirements that we are promulgating will also ensure that the facility's contribution to ambient concentrations of lead will not present an unacceptable level of risk. In addition, as discussed previously, we have not identified any additional cost-effective controls and we therefore conclude that the same level of controls to achieve acceptable risks will also provide an ample margin of safety.

With regard to discussing specific types of cancers potentially associated with exposure to a given HAP, we note that the cancer unit risk estimates used in the risk assessment are not associated with specific types of cancers, but rather with the risk of cancer in general. Moreover, since many of the cancer studies the unit risk estimates take into account are animal studies, there is appreciable uncertainty as to whether the same types of cancers would be seen in humans. Thus, we find it appropriate to express the results of our cancer assessment in terms of general cancer risk.

VI. Impacts of the Final Rule

The revisions to the Primary Lead Processing MACT standard will ensure that emissions from the one source in this source category do not present an unacceptable level of risk and will also provide an ample margin of safety. The estimated reductions include as much as 10 tons per year of lead from the furnace area and refining operations stacks. We also expect reductions will be achieved with the additional work practices, but we have not been able to quantify those reductions. These controls and work practices will also reduce emissions of other HAP emitted from the facility. The costs of these controls and work practices were not directly considered in the decision because these controls and practices are necessary to ensure that risks are acceptable. The EPA evaluated control practices and technology and associated costs in determining that the same requirements needed to achieve acceptable risks would also provide an ample margin of safety. In addition, we considered other available practices, processes and control technologies. For the same reason we concluded that no additional controls were necessary to provide an ample margin of safety, we concluded that there were no additional cost effective developments in practices, processes or control technologies for any sources other than the main stack.

VII. Statutory and Executive Order Reviews

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

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action." This action is a significant regulatory action because it raises novel legal and policy issues. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

The Office of Management and Budget (OMB) has approved the information collection requirements contained in this rule under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0414.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

This final rule includes new paperwork requirements for increased frequency for stack testing as described in 40 CFR 63.1546.

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

The EPA is adding affirmative defense to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden

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

Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emission events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small. For this reason, we estimate no more than 2 or 3 such occurrences for all sources subject to 40 CFR part 63, subpart TTT over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

For the Primary Lead Processing MACT standard, the ICR document prepared by the EPA, which has been revised to include the amendments to the standards, has been assigned the EPA ICR number 1856.08. Burden changes associated with these amendments result from the reporting and recordkeeping requirements of the affirmative defense provisions added to the rule. The change in respondents' annual reporting and recordkeeping burden associated with these amendments for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be 30 labor hours at a cost of $3,141 per year for the affirmative defense reporting. There will be no capital costs associated with the information collection requirements of the final rule. There is no estimated change in annual burden to the Federal government for these amendments. 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 in 40 CFR are listed in 40 CFR part 9. In addition, EPA is amending the table in 40 CFR part 9 of currently approved OMB control numbers for various regulations to list the regulatory citations for the information 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 these final rules 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 these final rules on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This final action will not impose any requirements on small entities. The costs associated with the new requirements in these final rules are not expected to present an undue burden to this industry as discussed above.

D. Unfunded Mandates Reform Act

This action contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for State, local, or tribal governments or the private sector. The action imposes no enforceable duty on any State, local or tribal governments or the private sector. Therefore, this action is not subject to the requirements of sections 202 or 205 of the UMRA.

These rules are also not subject to the regulatory requirements that might significantly or uniquely affect small governments. They contain no requirements that apply to such governments or impose obligations upon them.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. These final rules primarily affect private industry, and do not impose significant economic costs on State or local governments. Thus, Executive Order 13132 does not apply to this action.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effect on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

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

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997), because it is not economically significant as defined in Executive Order 12866. However, the agency does believe there is a disproportionate risk to children. Modeled ambient air lead

concentrations from the one facility in this source category are in excess of the NAAQS for lead, which was set to "provide increased protection for children and other at-risk populations against an array of adverse health effects, most notably including neurological effects in children, including neurocognitive and neurobehavioral effects." 73 FR 67007. However, the control measures promulgated in this notice will result in lead concentration levels that are in compliance with the lead NAAQS, thereby mitigating the risk of adverse health effects to children.

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

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse energy effect on the supply, distribution, or use of energy. This action will not create any new requirements for sources in the energy supply, distribution, or use sectors. Further, we have concluded that these final rules are not likely to have any adverse energy effects.

I. National Technology Transfer and Advancement Act

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

This action does not involve technical standards. Therefore, the EPA did not consider the use of any VCS.

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

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

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations, because it does not decrease the level of protection provided to human health or the environment, but in fact decreases emissions of lead. To examine the potential for any environmental justice issues that might be associated with this rule, we evaluated the distributions of HAP-related cancer and non-cancer risks across different social, demographic, and economic groups within the populations living near the one facility that is currently operating in this source category. Our analyses also show that, although there is potential for an adverse environmental and human health effects from emission of lead, it does not indicate any significant potential for disparate impacts to the specific demographic groups analyzed.

The rule would require additional control measures to address the identified environmental and health risks and would therefore, decrease risks to any populations exposed to 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. The EPA will submit a report containing this final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). The final rules will be effective on November 15, 2011.

List of Subjects for 40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: November 4, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency amends title 40, chapter I, of the Code of Federal Regulations as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

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

Subpart TTT—[Amended]

■ 2. Section 63.1541 is revised to read as follows:

§ 63.1541 Applicability.

(a) The provisions of this subpart apply to any facility engaged in producing lead metal from ore concentrates. The category includes, but is not limited to, the following smelting processes: Sintering, reduction, preliminary treatment, refining and casting operations, process fugitive sources, and fugitive dust sources. The sinter process includes an updraft or downdraft sintering machine. The reduction process includes the blast furnace, electric smelting furnace with a converter or reverberatory furnace, and slag fuming furnace process units. The preliminary treatment process includes the drossing kettles and dross reverberatory furnace process units. The refining process includes the refinery process unit. The provisions of this subpart do not apply to secondary lead smelters, lead refiners, or lead remelters.

(b) Table 1 of this subpart specifies the provisions of subpart A of this part that apply and those that do not apply to owners and operators of primary lead processors.

■ 3. Section 63.1542 is amended by adding a definition for "Affirmative defense," "Lead refiner," "Lead remelter," "Primary lead processor," and "Secondary lead smelter;" removing the definition of "Primary lead smelter;" and revising the definitions of "Fugitive dust source," "Furnace area," "Malfunction," "Materials storage and handling area," "Plant roadway," "Process fugitive source," "Refining and casting area," "Sinter machine area," and "Tapping location" to read as follows:

§ 63.1542 Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and

the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

Fugitive dust source means a stationary source of hazardous air pollutant emissions at a primary lead processor resulting from the handling, storage, transfer, or other management of lead-bearing materials where the source is not part of a specific process, process vent, or stack. Fugitive dust sources include roadways, storage piles, materials handling transfer points, and materials transport areas.

Furnace area means any area of a primary lead processor in which a blast furnace or dross furnace is located.

Lead refiner means any facility that refines lead metal that is not located at a primary lead processor.

Lead remelter means any facility that remelts lead metal that is not located at a primary lead processor.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Materials storage and handling area means any area of a primary lead processor in which lead-bearing materials (including ore concentrate, sinter, granulated lead, dross, slag, and flue dust) are stored or handled between process steps, including areas in which materials are stored in piles, bins, or tubs, and areas in which material is prepared for charging to a sinter machine or smelting furnace or other lead processing operation.

* * * * *

Plant roadway means any area of a primary lead processor that is subject to vehicle traffic, including traffic by forklifts, front-end loaders, or vehicles carrying ore concentrates or cast lead ingots. Excluded from this definition are employee and visitor parking areas, provided they are not subject to traffic by vehicles carrying lead-bearing materials.

Primary lead processor means any facility engaged in the production of lead metal from lead sulfide ore concentrates through the use of pyrometallurgical or other techniques.

Process fugitive source means a source of hazardous air pollutant emissions at a primary lead processor that is associated with lead smelting, processing or refining but is not the primary exhaust stream and is not a fugitive dust source. Process fugitive sources include sinter machine charging locations, sinter machine discharge locations, sinter crushing and sizing equipment, furnace charging locations, furnace taps, and drossing kettle and refining kettle charging or tapping locations.

Refining and casting area means any area of a primary lead processor in which drossing or refining operations occur, or casting operations occur.

Secondary lead smelter means any facility at which lead-bearing scrap material, primarily, but not limited to, lead-acid batteries, is recycled into elemental lead or lead alloys by smelting.

* * * * *

Sinter machine area means any area of a primary lead processor where a sinter machine, or sinter crushing and sizing equipment is located.

* * * * *

Tapping location means the opening through which lead and slag are removed from the furnace.

■ 4. Section 63.1543 is revised to read as follows:

§ 63.1543 Standards for process and process fugitive sources.

(a) No owner or operator of any existing, new, or reconstructed primary lead processor shall discharge or cause to be discharged into the atmosphere lead compounds in excess of 0.97 pounds per ton of lead metal produced from the aggregation of emissions discharged from air pollution control devices used to control emissions from the sources listed in paragraphs (a)(1) through (9) of this section.

(1) Sinter machine;

(2) Blast furnace;

(3) Dross furnace;

(4) Dross furnace charging location;

(5) Blast furnace and dross furnace tapping location;

(6) Sinter machine charging location;

(7) Sinter machine discharge end;

(8) Sinter crushing and sizing equipment; and

(9) Sinter machine area.

(b) No owner or operator of any existing, new, or reconstructed primary lead processor shall discharge or cause to be discharged into the atmosphere lead compounds in excess of 1.2 tons per year from the aggregation of the air pollution control devices used to control emissions from furnace area and refining and casting operations.

(c) The process fugitive sources listed in paragraphs (a)(4) through (8) of this section must be equipped with a hood and must be ventilated to a baghouse or equivalent control device. The hood design and ventilation rate must be consistent with American Conference of Governmental Industrial Hygienists recommended practices.

(d) The sinter machine area must be enclosed in a building that is ventilated to a baghouse or equivalent control device at a rate that maintains a positive in-draft through any doorway opening.

(e) Except as provided in paragraph (f) of this section, following the initial tests to demonstrate compliance with paragraphs (a) and (b) of this section, the owner or operator of a primary lead processor must conduct compliance tests for lead compounds on a quarterly basis (no later than 100 days following any previous compliance test).

(f) If the 12 most recent compliance tests demonstrate compliance with the emission limit specified in paragraphs (a) and (b) of this section, the owner or operator of a primary lead processor shall be allowed up to 12 calendar months from the last compliance test to conduct the next compliance test for lead compounds.

(g) The owner or operator of a primary lead processor must maintain and operate each baghouse used to control emissions from the sources listed in paragraphs (a)(1) through (9) and (b) of this section such that the alarm on a bag leak detection system required under § 63.1547(c)(8) does not sound for more than five percent of the total operating time in a 6-month reporting period.

(h) The owner or operator of a primary lead processor must record the date and time of a bag leak detection system alarm and initiate procedures to determine the cause of the alarm according to the corrective action plan required under § 63.1547(f) within 1 hour of the alarm. The cause of the alarm must be corrected as soon as practicable.

(i) At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

■ 5. Section 63.1544 is revised to read as follows:

§ 63.1544 Standards for fugitive dust sources.

(a) Each owner or operator of a primary lead processor must prepare, and at all times operate according to, a standard operating procedures manual that describes in detail the measures that will be put in place to control fugitive dust emissions from the sources listed in paragraphs (a)(1) through (a)(5) of this section that incorporates each of the specific work practices listed in paragraphs (a)(1) through (a)(5) of this section:

(1) *Plant roadways.* (i) Paved plant roadways must be cleaned using a wet sweeper unless the temperature falls below 39 degrees Fahrenheit or when the application of water results in the formation of ice. During periods when the temperature is below 39 degrees Fahrenheit, paved plant roadways must be cleaned using a high efficiency dry sweeper.

(ii) Continuously operate a sprinkler system to wet plant roadways to prevent fugitive dust entrainment. This sprinkler system must be operated except during periods when the temperature is less than 39 degrees Fahrenheit or when the application of water results in formation of ice.

(2) *Material storage and handling area(s).* (i) Chemically stabilize inactive concentrate storage piles a minimum of once every month to reduce particulate from wind born re-suspension.

(ii) Finished sinter must be sufficiently wetted to ensure fugitive dust emissions are minimized prior to loading to railcars.

(3) *Sinter machine area(s).* (i) Personnel doors must be kept closed during operations except when entering or exiting the furnace building by the aid of door weights or similar device for automatic closure.

(ii) Large equipment doors must remain closed except when entering or existing the building using an automatic closure system or equivalent lock-and-key method.

(iii) It may be necessary to open doors subject to the requirements in § 63.1544(a)(3)(i) and (ii) to prevent heat stress or exhaustion of workers inside the sinter plant building. Records of such periods must be included in the report required under § 63.1549(e)(8).

(4) *Furnace area(s).* (i) Personnel doors must be kept closed during operations except when entering or exiting the furnace building by the aid of door weights or similar device for automatic closure.

(ii) Large equipment doors must remain closed except when entering or existing the building using an automatic closure system or equivalent lock-and-key method.

(iii) It may be necessary to open doors subject to the requirements in § 63.1544(a)(4)(i) and (ii) to prevent heat stress or exhaustion of workers inside the blast furnace building. Records of such periods must be included in the report required under § 63.1549(e)(8).

(5) *Refining and casting area(s).* (i) Personnel doors must be kept closed during operations except when entering or exiting the furnace building by the aid of door weights or similar device for automatic closure.

(ii) Large equipment doors must remain closed except when entering or existing the building using an automatic closure system or equivalent lock-and-key method.

(iii) It may be necessary to open doors subject to the requirements in § 63.1544(a)(5)(i) and (ii) to prevent heat stress or exhaustion of workers inside the refining and casting building. Records of such periods must be included in the report required under § 63.1549(e)(8).

(b) Notwithstanding paragraph (c) of this section, the standard operating procedures manual shall be submitted to the Administrator or delegated authority for review and approval.

(c) Existing manuals that describe the measures in place to control fugitive dust sources required as part of a State implementation plan for lead shall satisfy the requirements of paragraph (a) of this section provided they include all the work practices as described in paragraphs (a)(1) through (5) of this section and provided they address all the sources listed in paragraphs (a)(1) through (5) of this section.

(d) At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

■ 6. Section 63.1545 is revised to read as follows:

§ 63.1545 Compliance dates.

(a) Each owner or operator of an existing primary lead processor must achieve compliance with the requirements in § 16.1543(a) no later than January 17, 2012. Each owner or operator of an existing primary lead processor must achieve compliance with the requirements of § 63.1544 no later than February 13, 2012. Each owner or operator of an existing primary lead processor must achieve compliance with the requirements in § 63.1543(b) and (e) of this subpart no later than November 15, 2013.

(b) Each owner or operator of a new primary lead processor must achieve compliance with the requirements of this subpart no later than January 17, 2012 or startup, whichever is later.

(c) Prior to the dates specified in § 63.1545(a), each owner or operator of an existing primary lead processor must continue to comply with the requirements of §§ 63.1543 and 63.1544 as promulgated in the June 4, 1999 NESHAP for Primary Lead Smelting.

(d) Each owner or operator of an existing primary lead processor must comply with the requirements of §§ 63.1547(g)(1) and (2), 63.1551, and Table 1 of Subpart TTT of Part 63 on November 15, 2011.

■ 7. Section 63.1546 is revised to read as follows:

§ 63.1546 Performance testing.

(a) The following procedures must be used to determine quarterly compliance with the emissions standard for lead compounds under § 63.1543(a) and (b) for existing sources:

(1) Each owner or operator of existing sources listed in § 63.1543(a)(1) through (9) and (b) must determine the lead compound emissions rate, in units of pounds of lead per hour according to the following test methods in appendix A of part 60 of this chapter:

(i) Method 1 must be used to select the sampling port location and the number of traverse points.

(ii) Method 2, 2F, 2G must be used to measure volumetric flow rate.

(iii) Method 3, 3A, 3B must be used for gas analysis.

(iv) Method 4 must be used to determine moisture content of the stack gas.

(v) Method 12 or Method 29 must be used to determine lead emissions rate of the stack gas.

(2) A performance test shall consist of at least three runs. For each test run with Method 12 or Method 29, the minimum sample time must be 60 minutes and the minimum volume must be 1 dry standard cubic meter (35 dry standard cubic feet).

(3) Performance tests shall be completed quarterly, once every 3 months, to determine compliance.

(4) The lead emission rate in pounds per quarter is calculated by multiplying

the quarterly lead emission rate in pounds per hour by the quarterly plant operating time, in hours as shown in Equation 1:

$$E_{Pb} = ER_{Pb} \times QPOT \quad \text{(Eq. 1)}$$

Where:

E_{Pb} = quarterly lead emissions, pounds per quarter;

ER_{Pb} = quarterly lead emissions rate, pounds per hour; and

QPOT = quarterly plant operating time, hours per quarter.

(5) The lead production rate, in units of tons per quarter, must be determined based on production data for the previous quarter according to the procedures detailed in paragraphs (a)(5)(i) through (iv) of this section:

(i) Total lead products production multiplied by the fractional lead content must be determined in units of tons.

(ii) Total copper matte production multiplied by the fractional lead content must be determined in units of tons.

(iii) Total copper speiss production multiplied by the fractional lead content must be determined in units of tons.

(iv) Total quarterly lead production must be determined by summing the values obtained in paragraphs (a)(5)(i) through (iii) of this section.

(6) To determine compliance with the production-based lead compound emission rate in § 63.1543(a), the quarterly production-based lead compound emission rate, in units of pounds of lead emissions per ton of lead produced, is calculated as shown in Equation 2 by dividing lead emissions by lead production.

$$CE_{Pb} = \frac{E_{Pb}}{P_{Pb}} \quad \text{(Eq. 2)}$$

Where:

CE_{Pb} = quarterly production-based lead compound emission rate, in units of pounds of lead emissions per ton of lead produced;

E_{Pb} = quarterly lead emissions, pounds per quarter; and

P_{Pb} = quarterly lead production, tons per quarter.

(7) To determine quarterly compliance with the emissions standard for lead compounds under § 63.1543(b), sum the lead compound emission rates for the current and previous three quarters for the sources in § 63.1543(b), as determined in accordance with paragraphs (a)(1) through (4) of this section.

(b) Owners and operators must perform an initial compliance test to demonstrate compliance with the sinter building in-draft requirements of § 63.1543(d) at each doorway opening in accordance with paragraphs (b)(1) through (4) of this section.

(1) Use a propeller anemometer or equivalent device.

(2) Determine doorway in-draft by placing the anemometer in the plane of the doorway opening near its center.

(3) Determine doorway in-draft for each doorway that is open during normal operation with all remaining doorways in their customary position during normal operation.

(4) Do not determine doorway in-draft when ambient wind speed exceeds 2 meters per second.

(c) Performance tests shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance of the affected source for the period being tested. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

■ 8. Section 63.1547 is revised to read as follows:

§ 63.1547 Monitoring requirements.

(a) Owners and operators of primary lead processors must prepare, and at all times operate according to, a standard operating procedures manual that describes in detail the procedures for inspection, maintenance, and bag leak detection and corrective action for all baghouses that are used to control process, process fugitive, or fugitive dust emissions from any source subject to the lead emission standards in §§ 63.1543 and 63.1544, including those used to control emissions from general ventilation systems.

(b) The standard operating procedures manual for baghouses required by paragraph (a) of this section must be submitted to the Administrator or delegated authority for review and approval.

(c) The procedures specified in the standard operating procedures manual for inspections and routine maintenance must, at a minimum, include the requirements of paragraphs (c)(1) through (8) of this section.

(1) Weekly confirmation that dust is being removed from hoppers through visual inspection or equivalent means of ensuring the proper functioning of removal mechanisms.

(2) Daily check of compressed air supply for pulse-jet baghouses.

(3) An appropriate methodology for monitoring cleaning cycles to ensure proper operation.

(4) Monthly check of bag cleaning mechanisms for proper functioning through visual inspection or equivalent means.

(5) Quarterly visual check of bag tension on reverse air and shaker-type baghouses to ensure that bags are not kinked (kneed or bent) or laying on their sides. Such checks are not required for shaker-type baghouses using self-tensioning (spring loaded) devices.

(6) Quarterly confirmation of the physical integrity of the baghouse through visual inspection of the baghouse interior for air leaks.

(7) Quarterly inspection of fans for wear, material buildup, and corrosion through visual inspection, vibration detectors, or equivalent means.

(8) Except as provided in paragraph (h) of this section, continuous operation of a bag leak detection system.

(d) The procedures specified in the standard operating procedures manual for maintenance must, at a minimum, include a preventative maintenance schedule that is consistent with the baghouse manufacturer's instructions for routine and long-term maintenance.

(e) The bag leak detection system required by paragraph (c)(8) of this section must meet the specifications and requirements of (e)(1) through (8) of this section.

(1) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligram per actual cubic meter (0.0044 grains per actual cubic foot) or less.

(2) The bag leak detection system sensor must provide output of relative particulate matter loadings, and the owner or operator must continuously record the output from the bag leak detection system.

(3) The bag leak detection system must be equipped with an alarm system that will sound when an increase in relative particulate loading is detected over a preset level, and the alarm must be located such that it can be heard or otherwise determined by the appropriate plant personnel.

(4) Each bag leak detection system that works based on the triboelectric effect must be installed, calibrated, and maintained in a manner consistent with guidance provided in the U.S. Environmental Protection Agency guidance document "Fabric Filter Bag Leak Detection Guidance" (EPA–454/R–98–015). Other bag leak detection systems must be installed, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations.

(5) The initial adjustment of the system must, at a minimum, consist of establishing the baseline output by adjusting the sensitivity (range) and the

averaging period of the device, and establishing the alarm set points and the alarm delay time.

(6) Following initial adjustment, the owner or operator must not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time, except as detailed in the approved SOP required under paragraph (a) of this section. In no event shall the sensitivity be increased by more than 100 percent or decreased more than 50 percent over a 365-day period unless a responsible official certifies that the baghouse has been inspected and found to be in good operating condition.

(7) For negative pressure, induced air baghouses, and positive pressure baghouses that are discharged to the atmosphere through a stack, the bag leak detector must be installed downstream of the baghouse and upstream of any wet acid gas scrubber.

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

(f) The standard operating procedures manual required by paragraph (a) of this section must include a corrective action plan that specifies the procedures to be followed in the event of a bag leak detection system alarm. The corrective action plan must include at a minimum, procedures to be used to determine the cause of an alarm, as well as actions to be taken to minimize emissions, which may include, but are not limited to, the following.

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

(2) Sealing off defective bags or filter media.

(3) Replacing defective bags or filter media, or otherwise repairing the control device.

(4) Sealing off a defective baghouse compartment.

(5) Cleaning the bag leak detection system probe, or otherwise repairing or maintaining the bag leak detection system.

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

(g) The percentage of total operating time the alarm on the bag leak detection system sounds in a 6-month reporting period must be calculated in order to determine compliance with the five percent operating limit in § 63.1543(g). The percentage of time the alarm on the bag leak detection system sounds must be determined according to paragraphs (g)(1) through (3) of this section.

(1) For each alarm where the owner or operator initiates procedures to determine the cause of an alarm within 1 hour of the alarm, 1 hour of alarm time must be counted.

(2) For each alarm where the owner or operator does not initiate procedures to determine the cause of the alarm within 1 hour of the alarm, alarm time will be counted as the actual amount of time taken by the owner or operator to initiate procedures to determine the cause of the alarm.

(3) The percentage of time the alarm on the bag leak detection system sounds must be calculated as the ratio of the sum of alarm times to the total operating time multiplied by 100.

(h) Baghouses equipped with HEPA filters as a secondary filter used to control process or process fugitive sources subject to the lead emission standards in § 63.1543 are exempt from the requirement in paragraph (c)(8) of this section to be equipped with a bag leak detector. The owner or operator of an affected source that uses a HEPA filter must monitor and record the pressure drop across the HEPA filter system daily. If the pressure drop is outside the limit(s) specified by the filter manufacturer, the owner or operator must take appropriate corrective measures, which may include, but not be limited to, the following:

(1) Inspecting the filter and filter housing for air leaks and torn or broken filters.

(2) Replacing defective filter media, or otherwise repairing the control device.

(3) Sealing off a defective control device by routing air to other comparable control devices.

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

(i) Owners and operators must monitor sinter machine building in-draft to demonstrate continued compliance with the operating standard specified in § 63.1543(d) in accordance with either paragraph (i)(1), (2), or (3) of this section.

(1) Owners and operators must check and record on a daily basis doorway in-draft at each doorway in accordance with the methodology specified in § 63.1546(b).

(2) Owners and operators must establish and maintain baseline ventilation parameters which result in a positive in-draft according to paragraphs (i)(2)(i) through (iv) of this section.

(i) Owners and operators must install, calibrate, maintain, and operate a monitoring device that continuously records the volumetric flow rate through each separately ducted hood; or install, calibrate, maintain, and operate a monitoring device that continuously records the volumetric flow rate at the control device inlet of each exhaust system ventilating the building. The flow rate monitoring device(s) can be installed in any location in the exhaust duct such that reproducible flow rate measurements will result. The flow rate monitoring device(s) must have an accuracy of plus or minus 10 percent over the normal process operating range and must be calibrated according to manufacturer's instructions.

(ii) During the initial demonstration of sinter building in-draft, and at any time the owner or operator wishes to re-establish the baseline ventilation parameters, the owner or operator must continuously record the volumetric flow rate through each separately ducted hood, or continuously record the volumetric flow rate at the control device inlet of each exhaust system ventilating the building and record exhaust system damper positions. The owner or operator must determine the average volumetric flow rate(s) corresponding to the period of time the in-draft compliance determinations are being conducted.

(iii) The owner or operator must maintain the volumetric flow rate(s) at or above the value(s) established during the most recent in-draft determination at all times the sinter machine is in operation. Volumetric flow rate(s) must be calculated as a 15-minute average.

(iv) If the volumetric flow rate is monitored at the control device inlet, the owner or operator must check and record damper positions daily to ensure they are in the positions they were in during the most recent in-draft determination.

(3) An owner or operator may request an alternative monitoring method by following the procedures and requirements in § 63.8(f) of the General Provisions.

(j) Each owner or operator of new or modified sources listed under § 63.1543 (a)(1) through (9) and (b) must install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring lead emissions and a continuous emission rate monitoring system (CERMS) subject to Performance Specification 6 of Appendix B to part 60.

(1) Each owner or operator of a source subject to the emissions limits for lead compounds under § 63.1543(a)and (b) must install a CEMS for measuring lead emissions within 180 days of promulgation of performance specifications for lead CEMS.

(i) Prior to promulgation of performance specifications for CEMS used to measure lead concentrations, an owner or operator must use the procedure described in § 63.1546(a)(1)

through (7) of this section to determine compliance.

(2) If a CEMS used to measure lead emissions is applicable, the owner or operator must install a CERMS with a sensor in a location that provides representative measurement of the exhaust gas flow rate at the sampling location of the CEMS used to measure lead emissions, taking into account the manufacturer's recommendations. The flow rate sensor is that portion of the system that senses the volumetric flow rate and generates an output proportional to that flow rate.

(i) The CERMS must be designed to measure the exhaust gas flow rate over a range that extends from a value of at least 20 percent less than the lowest expected exhaust flow rate to a value of at least 20 percent greater than the highest expected exhaust gas flow rate.

(ii) The CERMS must be equipped with a data acquisition and recording system that is capable of recording values over the entire range specified in paragraph (j)(2)(i) of this section.

(iii) Each owner or operator must perform an initial relative accuracy test of the CERMS in accordance with the applicable Performance Specification in Appendix B to part 60 of the chapter.

(iv) Each owner or operator must operate the CERMS and record data during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments.

(3) Each owner or operator must calculate the lead emissions rate in tons per year by summing all hours of CEMS data for a year to determine compliance with § 63.1543(b).

(i) When the CERMS are unable to provide quality assured data the following applies:

(A) When data are not available for periods of up to 48 hours, the highest recorded hourly emission rate from the previous 24 hours must be used.

(B) When data are not available for 48 or more hours, the maximum daily emission rate based on the previous 30 days must be used.

■ 9. Section 63.1548 is revised to read as follows:

§ 63.1548 Notification requirements.

(a) The owner or operator of a primary lead processor must comply with the notification requirements of § 63.9 of subpart A, General Provisions as specified in Table 1 of this subpart.

(b) The owner or operator of a primary lead processor must submit the standard operating procedures manual for baghouses required under § 63.1547(a) to the Administrator or delegated authority along with a notification that the primary lead processor is seeking review and approval of the manual and procedures. Owners or operators of existing primary lead processors must submit this notification no later than November 6, 2000. The owner or operator of a primary lead processor that commences construction or reconstruction after April 17, 1998, must submit this notification no later than 180 days before startup of the constructed or reconstructed primary lead processor, but no sooner than September 2, 1999.

■ 10. Section 63.1549 is revised to read as follows:

§ 63.1549 Recordkeeping and reporting requirements.

(a) The owner or operator of a primary lead processor must comply with the recordkeeping requirements of § 63.10 of subpart A, General Provisions as specified in Table 1 of this subpart.

(b) In addition to the general records required by paragraph (a) of this section, each owner or operator of a primary lead processor must maintain for a period of 5 years, records of the information listed in paragraphs (b)(1) through (10) of this section.

(1) Production records of the weight and lead content of lead products, copper matte, and copper speiss.

(2) Records of the bag leak detection system output.

(3) An identification of 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, and the date and time the cause of the alarm was corrected.

(4) Any recordkeeping required as part of the practices described in the standard operating procedures manual for baghouses required under § 63.1547(a).

(5) If an owner or operator chooses to demonstrate continuous compliance with the sinter building in-draft requirement under § 63.1543(d) by employing the method allowed in § 63.1547(i)(1), the records of the daily doorway in-draft checks, an identification of the periods when there was not a positive in-draft, and an explanation of the corrective actions taken.

(6) If an owner or operator chooses to demonstrate continuous compliance with the sinter building in-draft requirement under § 63.1543(d) by employing the method allowed in § 63.1547(i)(2), the records of the output from the continuous volumetric flow monitor(s), an identification of the periods when the 15-minute volumetric flow rate dropped below the minimum established during the most recent in-draft determination, and an explanation of the corrective actions taken.

(7) If an owner or operator chooses to demonstrate continuous compliance with the sinter building in-draft requirement under § 63.1543(d) by employing the method allowed in § 63.1547(i)(2), and volumetric flow rate is monitored at the baghouse inlet, records of the daily checks of damper positions, an identification of the days that the damper positions were not in the positions established during the most recent in-draft determination, and an explanation of the corrective actions taken.

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

(9) Records of actions taken during periods of malfunction to minimize emissions in accordance with §§ 63.1543(i) and 63.1544(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(c) Records for the most recent 2 years of operation must be maintained on site. Records for the previous 3 years may be maintained off site.

(d) The owner or operator of a primary lead processor must comply with the reporting requirements of § 63.10 of subpart A, General Provisions as specified in Table 1 of this subpart.

(e) In addition to the information required under § 63.10 of the General Provisions, the owner or operator must provide semi-annual reports containing the information specified in paragraphs (e)(1) through (9) of this section to the Administrator or designated authority.

(1) The reports must include records of all alarms from the bag leak detection system specified in § 63.1547(e).

(2) The reports must include a description of the actions taken following each bag leak detection system alarm pursuant to § 63.1547(f).

(3) The reports must include a calculation of the percentage of time the alarm on the bag leak detection system sounded during the reporting period pursuant to § 63.1547(g).

(4) If an owner or operator chooses to demonstrate continuous compliance with the sinter building in-draft requirement under § 63.1543(d) by employing the method allowed in § 63.1547(i)(1), the reports must contain an identification of the periods when there was not a positive in-draft, and an explanation of the corrective actions taken.

(5) If an owner or operator chooses to demonstrate continuous compliance with the sinter building in-draft requirement under § 63.1543(d) by employing the method allowed in § 63.1547(i)(2), the reports must contain an identification of the periods when the 15-minute volumetric flow rate(s) dropped below the minimum established during the most recent in-draft determination, and an explanation of the corrective actions taken.

(6) If an owner or operator chooses to demonstrate continuous compliance with the sinter building in-draft requirement under § 63.1543(d) by employing the method allowed in § 63.1547(i)(2), and volumetric flow rate is monitored at the baghouse inlet, the reports must contain an identification of the days that the damper positions were not in the positions established during the most recent in-draft determination, and an explanation of the corrective actions taken.

(7) The reports must contain a summary of the records maintained as part of the practices described in the standard operating procedures manual for baghouses required under § 63.1547(a), including an explanation of the periods when the procedures were not followed and the corrective actions taken.

(8) The reports shall contain a summary of the fugitive dust control measures performed during the required reporting period, including an explanation of any periods when the procedures outlined in the standard operating procedures manual required by § 63.1544(a) were not followed and the corrective actions taken. The reports shall not contain copies of the daily records required to demonstrate compliance with the requirements of the standard operating procedures manuals required under §§ 63.1544(a) and 63.1547(a).

(9) If there was a malfunction during the reporting period, the report shall also include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §§ 63.1543(i) and 63.1544(d), including actions taken to correct a malfunction.

■ 11. Section 63.1550 is revised to read as follows:

§ 63.1550 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(l) of the act, the authorities contained in paragraph (b) of this section must be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: No restrictions.

■ 12. Section 63.1551 is added to read as follows:

§ 63.1551 Affirmative defense for exceedance of emission limit during malfunction.

In response to an action to enforce the standards set forth in this subpart you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

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

(1) The excess emissions:

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

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

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

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

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

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

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

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

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

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

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

(b) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standards in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

■ 13. Table 1 to Subpart TTT of Part 63 is revised to read as follows:

TABLE 1 OF SUBPART TTT—GENERAL PROVISIONS APPLICABILITY TO SUBPART TTT

Reference	Applies to subpart TTT	Comment
* * *	*	* * *
63.6(a), (b), (c)	Yes.	
63.6(d)	No	Section reserved.
63.6(e)(1)(i)	No	See 63.1543(i) and 63.1544(d) for general duty requirement.
63.6(e)(1)(ii)	No.	
63.6(e)(1)(iii)	Yes.	
63.6(e)(2)	No	Section reserved.
63.6(e)(3)	No.	
63.6(f)(1)	No.	
63.6(g)	Yes.	
63.6(h)	No	No opacity limits in rule.
63.6(i)	Yes.	
63.6(j)	Yes.	
§63.7(a)–(d)	Yes.	
§63.7(e)(1)	No	See 63.1546(c).
§63.7(e)(2)–(e)(4)	Yes.	
63.7(f), (g), (h)	Yes.	
63.8(a)–(b)	Yes.	
63.8(c)(1)(i)	No.	
63.8(c)(1)(ii)	Yes.	
63.8(c)(1)(iii)	No.	
63.8(c)(2)–(d)(2)	Yes.	
63.8(d)(3)	Yes, except for last sentence.	
63.8(e)–(g)	Yes.	
63.9(a), (b), (c), (e), (g), (h)(1) through (3), (h)(5) and (6), (i) and (j).	Yes.	
63.9(f)	No.	
63.9(h)(4)	No	Reserved.
63.10(b)(2)(i)	No.	
63.10(b)(2)(ii)	No	See 63.1549(b)(9) and (10) for recordkeeping of occurrence and duration of malfunctions and recordkeeping of actions taken during malfunction.
63.10(b)(2)(iii)	Yes.	
63.10(b)(2)(iv)–(b)(2)(v)	No.	
63.10(b)(2)(vi)–(b)(2)(xiv)	Yes.	
63.(10)(b)(3)	Yes.	
63.10(c)(1)–(9)	Yes.	
63.10(c)(10)–(11)	No	See 63.1549(b)(9) and (10) for recordkeeping of malfunctions.
63.10(c)(12)–(c)(14)	Yes.	
63.10(c)(15)	No.	
63.10(d)(1)–(4)	Yes.	
63.10(d)(5)	No	See 63.1549(e)(9) for reporting of malfunctions.
63.10(e)–(f)	Yes.	
* * *	* * *	* * *

[FR Doc. 2011–29287 Filed 11–14–11; 8:45 am]
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TABLE 1 OF T01–0533—Continued

	42°19.4′ N, 071°02.9′ W.
8.2 Celebrate the Clean Harbor Swim	• Date: August 13, 2011. • Rain Date: following day. • Time: 9 a.m. to 12 p.m. • Location: All waters of Gloucester Harbor within the following points (NAD 83): 42°35.3′ N, 070°39.8′ W. 42°35.9′ N, 070°39.2′ W. 42°35.9′ N, 070°39.8′ W. 42°35.3′ N, 070°40.2′ W.
8.3 Boston Light Swim	• Date: August 13, 2011. • Time: 6 a.m. to 12 p.m. • Location: All waters of Boston Harbor between the L Street Bath House and Little Brewster Island within the following points (NAD 83): 42°19.7′ N, 071°02.2′ W. 42°19.9′ N, 071°10.7′ W 42°19.8′ N, 070°53.6′ W. 42°19.6′ N, 070°53.4′ W.
9	September
9.1 Mayflower Triathlon	• Date: September 3, 2011. • Time: 7:30 a.m. to 8:30 a.m. • Location: All waters of Plymouth Inner Harbor within the following points (NAD 83): 41°58.3′ N, 070°40.6′ W 41°58.7′ N, 070°39.1′ W. 41°56.8′ N, 070°37.8′ W. 41°57.1′ N, 070°39.2′ W.
9.2 Duxbury Beach Triathlon	• Date: September 24, 2011. • Time: 9 a.m. to 10 a.m. • Location: All waters of Duxbury Bay on the south side of the Powder Point Bridge within the following points (NAD 83): 42°02.8′ N, 070°39.1′ W. 42°03.0′ N, 070°38.7′ W. 42°02.8′ N, 070°38.6′ W. 42°02.7′ N, 070°39.0′ W.

Dated: July 7, 2011.

J.N. Healey,

Captain, U.S. Coast Guard, Captain of the Port Sector Boston.

[FR Doc. 2011–17983 Filed 7–15–11; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 63

[EPA–HQ–OAR–2003–0146; FRL–9439–2]

RIN 2060–AO55

National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; partial withdrawal.

SUMMARY: On October 28, 2009, the EPA proposed to withdraw the residual risk and technology review portions of the final rule amending the National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries. EPA is now providing final notice of the partial withdrawal.

DATES: As of August 17, 2011, EPA withdraws portions of the final rule signed by then Administrator Stephen Johnson on January 16, 2009.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2003–0146. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information 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. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, Environmental Protection Agency, 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: Ms. Brenda Shine, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Refining and Chemicals Group (E143–01), Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number: (919) 541–3608; fax number: (919) 541–0246; e-mail address: *shine.brenda@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background Information

Section 112 of the Clean Air Act (CAA) establishes a two-stage regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. In the first stage, after the EPA has identified categories of

sources emitting one or more of the HAP listed in section 112(b) of the CAA, section 112(d) calls for the Administrator to promulgate national emission standards for hazardous air pollutants for those sources. The EPA is then required to review these technology-based standards, and to revise them "as necessary (taking into account developments in practices, processes, and control technologies)" no less frequently than every 8 years, under CAA section 112(d)(6). The second stage in standard-setting focuses on reducing any remaining "residual" risk according to CAA section 112(f).

On January 16, 2009, then Administrator Stephen Johnson signed a final rule amending the National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, and the signed rule was made publicly available on the EPA's website. The signed rule included several different actions. First, it promulgated maximum achievable control technology (MACT) standards under CAA sections 112(d)(2) and (3) for heat exchange systems, which the EPA had not addressed in the original Refinery MACT 1 rule (40 CFR part 63, subpart CC). Second, pursuant to CAA section 112(f)(2), the rule addressed residual risk for all Refinery MACT 1 sources, including heat exchange systems. Third, it addressed the technology review pursuant to CAA section 112(d)(6) for all sources addressed in the original Refinery MACT 1 rule. Finally, the rule updated the table in the Refinery MACT 1 standards (Table 6) that cross-references the General Provisions in 40 CFR part 63, subpart A, and made a few additional clarifications to dates and cross-references in the Refinery MACT 1 standards.

The signed rule was submitted to the Office of the Federal Register for publication. Rahm Emanuel, Assistant to the President and Chief of Staff, issued a memorandum on January 20, 2009, directing Agencies to withdraw from the Office of the Federal Register "all proposed or final regulations that have not been published in the **Federal Register** so that they can be reviewed and approved by a department or agency head." Although there was an exception for "regulations subject to statutory or judicial deadlines," the Agency chose not to apply the exception in this case. One portion of the final rule, the CAA section 112(d)(6) review, was performed pursuant to the terms of a Consent Decree, which, as modified, required that by January 16, 2009, the EPA "shall sign and promptly forward to the **Federal Register** for publication either final revisions to the standards for petroleum refineries in 40 CFR part 63, subpart CC pursuant to 42 U.S.C. 7412(d)(6) or a final determination that no revisions are necessary." Then Administrator Stephen Johnson signed the rule on January 16, 2009, and promptly forwarded it to the Office of the Federal Register, thus, fulfilling this obligation.[1]

Upon further review, the EPA determined that the residual risk and technology reviews may not accurately characterize the risk posed by this source category. Shortly after the rule was signed, the EPA responded to a *Request for Correction* under the EPA's *Information Quality Guidelines* from the city of Houston.[2] In that response, we recognized that we were currently taking action (and planned to take additional action) to gather better emissions information from the refining industry. Additionally, we noted that, during the comment period on the proposed rule, similar issues were raised concerning the representativeness of the emissions data and whether they provided an accurate basis for characterizing the risks posed.

After consideration of the public comments on the proposal to withdraw portions of the final rule, we are providing final notice of the Agency's decision to partially withdraw the final rule. As stated in the preamble to the proposed withdrawal, the EPA will provide the public with an opportunity to comment on any new proposed rule that may be issued addressing the residual risk and technology review requirements of the CAA for this source category.

II. Summary of Comments and Responses

The EPA received a total of six comment letters concerning the proposed partial withdrawal. Comment letters were received from industry trade associations, local environmental organizations, environmental groups, and members of the public. Summaries of the comments and our complete responses are included in the following section.

Comment: Four commenters supported the EPA's proposed partial withdrawal of the Refinery MACT 1 standards signed on January 16, 2009, and supported further analysis leading to a revised set of proposed standards. Several of these commenters asserted that the withdrawal is necessary because the EPA failed to adequately address their comments on the standards that were proposed on September 4, 2007 (72 FR 50716), and November 10, 2008 (73 FR 66694). Some of the comments submitted on those previous proposals and reiterated by the commenters included: (1) Objections to the EPA's interpretation of the CAA requirement that the standards provide an "ample margin of safety"; (2) assertions that the maximum individual lifetime cancer risk allowed by the CAA is 1 in 1 million; (3) objections to the length of time allowed for compliance with standards for storage vessels with floating roofs; (4) identification of multiple deficiencies in the risk assessment methodology, including use of actual emissions rather than allowable emissions and the estimation of emissions at census block centroids rather than property lines; and (5) assertions that the emissions data used in the risk assessment were underestimated and unrepresentative. The commenters requested that the EPA collect more accurate emissions data and re-analyze the residual risk for Refinery MACT 1 using a methodology without the identified deficiencies.

Response: We appreciate the four commenters' support for the withdrawal of the residual risk and technology review portions of the revisions to the Refinery MACT 1 standards. In this notice, the EPA is not making any decisions regarding the scope of residual risk and technology review standards under the CAA or on the specific data that would form the basis for a particular decision. Substantive comments on those issues should be raised in the context of future proposed rules addressing the CAA residual risk and technology review for one or more specific source categories.

Comment: Two commenters objected to the proposed withdrawal of the residual risk and technology review portions of the Refinery MACT 1 standards that were signed on January 16, 2009. These commenters noted that the EPA spent several years collecting data and considering stakeholder comments, finally reaching the conclusion that the Refinery MACT 1 standards provide an ample margin of safety based on data that the EPA judged to be representative of the source category. The commenters asserted that

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[1] We note that on January 30, 2009, the litigants notified EPA by letter that they believed the Agency had discharged its obligation under the Consent Decree, and that "further review of the rule pursuant to the Emanuel memo will not violate the Consent Decree." (See Docket Item No. EPA–HQ–OAR–2003–0146–0209.)

[2] Letter to U.S. EPA Information Quality Guidelines staff from the Honorable Bill White, Mayor of Houston, July 9, 2008, Docket Item No. EPA–HQ–OAR–2003–0146–0166.3; EPA's response is Letter to Mayor Bill White, Houston, Texas, from Elizabeth Craig, Acting Assistant Administrator, Office of Air and Radiation, U.S. EPA, April 7, 2009. (See Docket Item No. EPA–HQ–OAR–2003–0146–0210.)

the docket for the Refinery MACT 1 rulemaking (Docket ID EPA–HQ–OAR–2003–0146) does not include any specific support for the EPA's decision to reject that previous conclusion. According to the commenters, the only support for withdrawing the rule and redoing the analyses is provided in public comments submitted for the proposed rules, and the EPA considered those comments prior to finalizing the rule signed on January 16, 2009. The commenters requested that the EPA present any additional data received or analyses performed since January 16, 2009, to support withdrawal of the standards, and clearly explain any differences in assumptions or methodologies used in the analyses.

One commenter asserted that residual risk and technology review for Refinery MACT 1 has been a time- and resource-consuming process, and due to the EPA's other obligations under the CAA, it is not in the best interest of the public for the EPA to repeat the entire process without good cause. The commenter detailed a number of analyses in the docket showing that the EPA believed its emissions estimates and risk assessment methodologies were appropriate for the rulemaking. The commenter also noted that, if the EPA always postponed regulatory action because data may become available in the future, no regulatory actions would ever be completed. According to the commenter, refiners continue to make improvements in emissions reductions, and the heat exchange system standards will reduce emissions from cooling towers, so further data collection would only serve to support the conclusion that the current standards provide an ample margin of safety.

Two commenters addressed the EPA's responsibilities under the Data Quality Act (DQA) related to the *Request for Correction* filed by Mayor White of Houston (RFC 02003). The commenters stated that the EPA fulfilled its DQA obligations through its response to Mayor White on April 7, 2009 (Docket Item No. EPA–HQ–OAR–2003–0146–0210), which describes the steps that the EPA plans to take to improve annual emissions estimates. Since the EPA has addressed the DQA concerns raised by Mayor White, the commenters asserted that it is not necessary for the Agency to take action on the proposed withdrawal of the Refinery MACT 1 standards to further address those concerns.

Response: As the commenters noted, we did reach the conclusions presented in the rule that was signed on January 16, 2009, through analysis of the data we had at the time. The commenters are correct that, as of the time of the proposed withdrawal, we had not yet received any specific, additional data to support changing the conclusions reached in the final rule. However, our proposal was not based on the receipt of such information. Our decision to withdraw the residual risk and technology review portions of the January 16, 2009, rule does not mean that we have made a decision to change our conclusions regarding what requirements are necessary and appropriate for the Refinery MACT 1 standards. Instead, as we noted when we proposed the withdrawal, we believe it is necessary to develop a more robust analysis based on the improved information we are in the process of gathering and developing.

With respect to duplicating the "time- and resource-consuming process" associated with the risk and technology review, we note that the EPA is now initiating the risk and technology review for the Refinery MACT 2 standards (40 CFR part 63, subpart UUU) and plans to conduct the Refinery MACT 1 and 2 reviews at the same time. Thus, our data collection efforts for purposes of the Refinery MACT 2 risk and technology review will also provide a significant portion of the information we will need for purposes of our new residual risk and technology review of the Refinery MACT 1 standards. Moreover, we believe that by more closely aligning our risk and technology review for Refinery MACT 1 and 2 sources, we will be able to develop a significantly improved analysis of the risks associated with petroleum refineries, and, therefore, can better determine the most effective way to address any residual risk posed by emissions from petroleum refineries. We see significant benefits in combining these efforts, both in terms of a more transparent risk evaluation of these co-located sources for the neighboring public and in terms of more consolidated standards for the regulated community. The EPA has already taken action to gather better emissions information from the refining industry, and to follow through on the commitments made in the response letter to Mayor White of Houston (Docket Item No. EPA–HQ–OAR–2003–0146–0210). For these reasons, we have concluded that the benefits of a consolidated risk and technology review outweigh the incremental analytical effort required to perform a new risk assessment for Refinery MACT 1 sources after collecting this more robust data.

One commenter suggested that the additional data may lead to the conclusion that the existing standards provide an ample margin of safety. We agree that is a possible outcome; however, any conclusions regarding the residual risk review for the Refinery MACT 1 standards will need to await our consideration of the more robust data we are now gathering. Those data will provide greater certainty for the final conclusions, and help to ensure the final standards are technically and legally defensible.

Finally, the EPA agrees that it has responded to the DQA request from Mayor White of Houston through the April 7, 2009, letter identified by the two commenters (Docket Item No. EPA–HQ–OAR–2003–0146–0210). In that letter, we outlined several initiatives that were either ongoing or planned for the near future in order to improve the quality of data we have concerning emissions from petroleum refineries, and we are continuing to move forward with all of those initiatives. We plan to use this improved information as we move forward to address emissions from petroleum refineries, including performing the residual risk and technology review for Refinery MACT 1 and 2 sources.

Comment: Two commenters noted that, if the EPA proceeds with the proposed partial withdrawal of Refinery MACT 1 standards, the Agency should make clear that the withdrawal completes the action related to the September 4, 2007, proposal. In other words, the commenters stated that the date for determining compliance with any new standards would be the proposal date of those new standards rather than September 4, 2007.

Response: We agree with the commenters. The appropriate dates for determining compliance with future standards would be the dates those standards are proposed and finalized.

Statutory and Executive Order Reviews

Under the CAA, the Administrator is withdrawing a final action that was signed by the Administrator and made publicly available on the the EPA website, but that never took effect through publication in the **Federal Register**. This action:

- Is a "significant regulatory action" subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501, *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities

under the Regulatory Flexibility Act (5 U.S.C. 601, *et seq.*);

• Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);

• Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);

• Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);

• Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);

• Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA;

• Does not provide the EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994); and

• This notice does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because it will not impose substantial direct costs on tribal governments or preempt tribal law.

List of Subjects

40 CFR Part 9

Environmental protection, Reporting and recordkeeping requirements.

40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Reporting and recordkeeping requirements.

Dated: July 8, 2011.

Lisa P. Jackson,

Administrator.

[FR Doc. 2011–17901 Filed 7–15–11; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 97

[FRL–9435–6]

Data Availability Concerning Transport Rule Allowance Allocations to Existing Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notification of data availability (NODA).

SUMMARY: In the Transport Rule Federal Implementation Plans (FIPs), EPA finalized allowance allocations for 2012 and thereafter to existing units subject to the Transport Rule FIP trading programs in Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. As required in the Transport Rule, this NODA notifies the public of the availability of data on these allowance allocations for existing units. Through this NODA, EPA is also making available to the public the data upon which the allocations were based.

FOR FURTHER INFORMATION CONTACT: Questions concerning this action should be addressed to Brian Fisher, telephone (202) 343–9633, and e-mail *fisher.brian@epa.gov,* Michael Cohen, telephone (202) 343–9497 and e-mail *cohen.michael@epa.gov,* or Robert Miller, telephone (202) 343.9077, and e-mail *miller.robertl@epa.gov.* The mailing address for the aforementioned contacts is U.S. Environmental Protection Agency, CAMD (6204J), 1200 Pennsylvania Ave., NW., Washington, DC 20460.

SUPPLEMENTARY INFORMATION: The detailed unit-by-unit data, calculations, and allowance allocation determinations are set forth in a technical support document in an Excel spreadsheet format titled "Unit Level Allocations Under the Transport Rule FIP" and available on EPA's Web site at *http://www.epa.gov/airtransport/actions.html.*

EPA is not requesting responses to the data made available through this NODA, which makes available data on allowance allocations finalized in the Transport Rule. Providing an allocation to an existing unit does not constitute a determination that the unit is a covered unit, and not providing an existing-unit allocation to a unit does not constitute a determination that the unit is not a covered unit. *See* §§ 97.411(a)(1), 97.511(a)(1), 97.611(a)(1), and 97.711(a)(1) of the Transport Rule.

Under the Transport Rule FIPs, EPA must record allowance allocations by certain deadlines. In particular, allowance allocations addressed by this NODA for existing units for 2012 must be recorded, within 90 days of the publication of the Transport Rule in the **Federal Register**, in the compliance accounts of existing units. *See* §§ 97.421(a), 97.521(a), 97.621(a), and 97.721(a) of the Transport Rule.

For 2013 and beyond, the Administrator must record, by certain specified deadlines, allowance allocations for existing units. *See* §§ 97.421(b) through (f), 97.521(b) through (f), 97.621(b) through (f), and 97.721(b) through (f) of the Transport Rule.

Under certain circumstances, the allowance allocations addressed in this NODA to existing units are subject to termination or correction, and the provisions establishing these allocations may be replaced by a SIP revision. *See* §§ 97.411(a)(2), 97.511(a)(2), 97.611(a)(2), and 97.711(a)(2) (concerning termination of allocations of non-operating units) and 97.411(c), 97.511(c), 97.611(c), and 97.711(c) (concerning incorrect allocations) of the Transport Rule and §§ 52.38(a)(3) through (5) and (b)(3) through (5) and 52.39(d) through (i) of the Transport Rule (concerning SIP revisions).

Dated: July 6, 2011.

Jackie Krieger,

Chief of Staff, Office of Atmospheric Programs.

[FR Doc. 2011–17903 Filed 7–15–11; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 300

[EPA–HQ–SFUND–1983–0002; FRL–9440–4]

National Oil and Hazardous Substances Pollution Contingency Plan; National Priorities List

AGENCY: Environmental Protection Agency.

ACTION: Withdrawal of direct final rule.

SUMMARY: On May 24, 2011, EPA published a Notice of Intent for Partial Deletion (76 FR 30081) and a direct final rule of Partial Deletion (76 FR 30027) for the remaining portions of Operable Unit 9 (OU9), the Residential Populated Areas, of the California Gulch Superfund Site (Site), located in Lake County, Colorado, from the National Priorities List. The EPA is withdrawing the Final Rule of Partial Deletion due to adverse comments that were received during the public comment period. After consideration of the comments received, if appropriate, EPA will publish a Notice of Partial Deletion in the **Federal Register** based on the parallel Notice of Intent for Partial Deletion and place a copy of the final partial deletion package, including a

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2008–0708, FRL–9277–3]

RIN 2060–AQ78

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule; amendments.

SUMMARY: EPA is taking direct final action to promulgate amendments to a final rule that provided national emission standards for hazardous air pollutants for existing stationary spark ignition reciprocating internal combustion engines. The final rule was published on August 20, 2010. This direct final action amends certain regulatory text to clarify compliance requirements related to continuous parameter monitoring systems. EPA is also correcting minor typographical errors in the regulatory text to the August 20, 2010, action.

DATES: The direct final rule is effective on May 9, 2011, without further notice, unless EPA receives significant adverse written comment by April 8, 2011 on any portion of this rule, or if a public hearing is requested by March 16, 2011. If significant adverse comments are received on any or all of the amendments, EPA will publish a timely withdrawal in the **Federal Register** clarifying which provisions will become effective and which provisions are being withdrawn due to adverse comment.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2008–0708, by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail: a-and-r-docket@epa.gov.*
- *Fax:* (202) 566–9744.
- *Mail:* U.S. Postal Service, send comments to: EPA Docket Center (6102T), National Emission Standards for Hazardous Air Pollutant for Stationary Reciprocating Internal Combustion Engines Docket, Docket ID No. EPA–HQ–OAR–2008–0708, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget, *Attn:* Desk Officer for EPA, 725 17th St., NW., Washington, DC 20503.
- *Hand Delivery:* In person or by courier, deliver comments to: EPA Docket Center (6102T), National Emission Standards for Hazardous Air Pollutant for Stationary Reciprocating Internal Combustion Engines Docket, Docket ID No. EPA–HQ–OAR–2008–0708, EPA West, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information. Please include a total of two copies.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2008–0708. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. EPA also relies on documents in Docket ID Nos. EPA–HQ–OAR–2002–0059, EPA–HQ–OAR–2005–0029, and EPA–HQ–OAR–2005–0030, and incorporated those dockets into the record for this action. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, 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 Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Melanie King, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541–2469; facsimile number (919) 541–5450; e-mail address *king.melanie@epa.gov.*

SUPPLEMENTARY INFORMATION:

Organization of This Document. The following outline is provided to aid in locating information in the preamble.

I. What is the background for the amendments?
II. What are the changes to the final rule?
III. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act of 1995
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. What is the background for the amendments?

On August 20, 2010 (75 FR 51570), EPA issued final amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE). EPA has subsequently determined, following discussions with affected parties, that the final rule warrants clarification in certain areas. First, certain portions of

the operation and maintenance requirements for continuous parameter monitoring systems (CPMS) are unclear. Second, sources asked for guidance regarding the requirement to conduct a temperature measurement calibration check. Finally, EPA is correcting an inadvertent error in the definition for "spark ignition." This action makes these clarifications and corrects these errors.

EPA is issuing the amendments as a direct final rule, without a prior proposal, because we view the revisions as noncontroversial and anticipate no adverse comment. However, in the Proposed Rules section of this **Federal Register** notice, EPA is publishing a separate document that will serve as the proposal to amend the RICE NESHAP if significant adverse comments are filed. EPA will not institute a second comment period on this action. Any parties interested in commenting must do so at this time. EPA would address all public comments in any subsequent final rule based on the proposed rule.

II. What are the changes to the final rule?

This direct final rule clarifies the provisions related to the data collection requirements for CPMS. After promulgation of the August 20, 2010, final rule, affected sources indicated that the CPMS operation, maintenance, and data collection requirements in 40 CFR 63.6625(b) were unclear. In particular, sources were not clear about the intent of the requirements for minimum availability of data. This action clarifies those requirements. It specifies that the requirement to monitor operating parameters on a continuous basis applies at all times the process is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities. This direct final rule also corrects an inadvertent error in the averaging time for the operating parameter data. Paragraph 40 CFR 63.6625(b)(4) required sources to determine a 3-hour block average of the parameter, which was not consistent with the requirements in Table 6 of 40 CFR part 63, subpart ZZZZ to determine a 4-hour rolling average. This action clarifies that sources should determine the 4-hour rolling average as specified in Table 6 to 40 CFR part 63, subpart ZZZZ and removes the reference to a 3-hour block average in 40 CFR 63.6625(b). The operating parameter data should be reduced to 1-hour averages, and the 4-hour rolling average should be determined using the rolling average of the four hourly averages.

Affected sources were also unclear regarding the requirement in 40 CFR 63.6625(k)(4) to conduct a temperature measurement calibration check at least every 3 months, and asked EPA for guidance on appropriate methods for conducting the calibration check. More specifically, sources struggled with the intention of the term "calibration check," wondering whether classical techniques such as the use of ice and boiling water baths would be the sole acceptable means of demonstrating a "calibration check." In addition, sources wondered whether just the sensor or the entire system should be subject to a "calibration check." This action replaces the term "calibration check" with "system accuracy audit" to better reflect EPA's intent. EPA recognizes that there are many ways for a source to demonstrate that its measurement system—as opposed to individual sensors—are producing and should be expected to continue producing valid data, and EPA affords sources the ability to tailor their monitoring plans to accommodate their system accuracy audit preferences. System accuracy audit techniques could include, but are not limited to, the use of redundant sensors or the use of a reference temperature gauge inserted in a thermal well co-located with the CPMS sensor. In both of the examples given above, each sensor would provide an assessment of the other's operation as demonstrated through a comparison of their individual values, and, when coupled with the other parts of a system accuracy audit and approved by EPA, could fulfill the rule requirements. Affected sources also indicated that the requirement to conduct quarterly checks of the temperature measurement device was unreasonable because engines may be located in remote locations that could be difficult for personnel trained in the equipment performance check procedures to reach on a quarterly basis. EPA recognizes that for these sources, the requirement to conduct quarterly checks may be too burdensome given the remote location of the engines, and has determined that annual checks of the temperature measurement device equipment are acceptable for stationary engines to ensure the equipment is producing valid data. EPA therefore is amending the requirement to specify that the temperature measurement device checks must be performed on an annual basis rather than quarterly.

The August 20, 2010, final amendments specified that the engine owner/operator must develop and submit for approval a site-specific monitoring plan for each CPMS. The monitoring plan must address elements of monitoring system design, performance, and data quality assurance and quality control consistent with the general provisions in part 63 and requirements of 40 CFR part 63, subpart ZZZZ. EPA notes that 40 CFR 63.8(f)(4) of the General Provisions allows the source to use the monitoring plan development and approval process to propose and apply alternatives to CPMS quality assurance and quality control requirements identified in the rule.

Affected sources also indicated that there was insufficient time for sources that were already subject to 40 CFR part 63 subpart ZZZZ to comply with the CPMS operation and maintenance requirements established in the August 20, 2010, final rule. EPA agrees that it is appropriate to provide a period of lead time for sources that would have been immediately affected by the new specifications for CPMS operation and maintenance. EPA is therefore amending the final rule to provide an additional 180 days before sources must comply with the CPMS operation and maintenance procedures in 40 CFR 63.6625(b).

This action also corrects an inadvertent error in 40 CFR 63.6603(a), which should have referenced Table 1b to 40 CFR part 63, subpart ZZZZ in addition to Table 2b. Table 1b includes the operating limitation requirements for existing stationary spark ignition four-stroke rich burn engines greater than 500 horsepower (HP) located at area sources of hazardous air pollutants. The introductory text to Tables 1b and 2b should also have contained a reference to 40 CFR 63.6603, and this action corrects that inadvertent error. This action also corrects an inadvertent error in Table 1b to 40 CFR part 63, subpart ZZZZ. The last line of Item 2 in Table 6 should have read "* * * and not using NSCR," and this action corrects that inadvertent error.

This action also clarifies the initial compliance requirements in Table 5 to 40 CFR part 63, subpart ZZZZ. The table as finalized did not clearly indicate the initial compliance requirements for existing non-emergency stationary engines larger than 500 HP complying with the option to limit the concentration of carbon monoxide (CO) or formaldehyde. The requirements were only shown for existing non-emergency stationary engines larger than 500 HP complying with the option to meet a percent reduction requirement for CO or formaldehyde. The requirements for those engines meeting a concentration limit are the same as those meeting a percent reduction limit,

except that for those engines meeting a concentration limit, emissions are not required to be measured at the inlet of the emission control device as well as the outlet. This action also corrects an inadvertent error in Table 6 to 40 CFR part 63, subpart ZZZZ. Item 13.a. in Table 6 should have read "* * * and not using an oxidation catalyst or NSCR," and this action corrects that inadvertent error.

Finally, this action corrects the definition for "Spark ignition." The word "with" was inadvertently omitted from the definition, and EPA is amending the definition to insert "with" immediately following the phrase "A gasoline-fueled engine; or any other type of engine. * * *"

III. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866, Regulatory Planning and Review (58 FR 51735, October 4, 1993), this action is not a "significant regulatory action" and is, therefore, not subject to review by the Office of Management and Budget (OMB). This action is a clarification of and correction to certain text in the final rule and is not a "major rule" as defined by 5 U.S.C. 804(2). However, the final rule promulgated on August 20, 2010, was reviewed by OMB.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. This action adds clarifications and corrections to the final standards. However, OMB has previously approved the information collection requirements contained in the existing regulation under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0548. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

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

For purposes of assessing the impact of this rule on small entities, small entity is defined as: (1) A small business as defined by Small Business Administration (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impact of this direct final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small because it does not add any additional regulatory requirements because this action only clarifies the existing compliance requirements and corrects typographical errors.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act (UMRA), 2 U.S.C 1531–1538, requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Federal agencies must also develop a plan to provide notice to small governments that might be significantly or uniquely affected by any regulatory requirements. The plan must enable officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates and must inform, educate, and advise small governments on compliance with the regulatory requirements.

This direct 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. Thus, this final rule is not subject to the requirements of section 202 and 205 of the UMRA.

This final action is also not subject to the requirements of section 203 of the UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This final action contains no requirements that apply to such governments, imposes no obligations upon them, and will not result in expenditures by them of $100 million or more in any one year or any disproportionate impacts on them.

E. Executive Order 13132: Federalism

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 direct 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. None of the affected facilities are owned or operated by State governments. Thus, Executive Order 13132 does not apply to these final rules.

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

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or EPA consults with tribal officials early in the process of developing the regulation and develops a tribal summary impact statement.

This direct final rule does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. The final rule imposes no new requirements on the one tribally owned facility. Thus, Executive Order 13175 does not apply to this 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 action is not subject to Executive Order 13211 (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 104–113 (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

This action does not involve changes to the technical standards related to test methods or monitoring methods; thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272) do not apply.

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

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

The direct final rule does not involve special consideration of environmental justice-related issues as required by Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (59 FR 7629, February 16, 1994), because it does not change any regulatory requirements. This action merely corrects and clarifies existing requirements.

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 action is effective May 9, 2011.

List of Subjects in 40 CFR Part 63

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

Dated: March 1, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

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

Subpart ZZZZ—[Amended]

■ 2. Section 63.6603 is amended by revising paragraph (a) to read as follows:

§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

* * * * *

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 1b and Table 2b to this subpart that apply to you.

* * * * *

■ 3. Section 63.6625 is amended by revising paragraph (b) and removing paragraph (k) to read as follows:

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

* * * * *

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (5) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-

specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

* * * * *

■ 4. Section 63.6635 is amended by revising paragraphs (b) and (c) to read as follows:

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

* * * * *

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

■ 5. Section 63.6675 is amended by revising the definition of *Spark ignition* to read as follows:

§ 63.6635 What definitions apply to this subpart?

* * * * *

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

* * * * *

■ 6. Table 1b to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed Spark Ignition 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions and Existing Spark Ignition 4SRB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions and existing 4SRB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O_2 and using NSCR.	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O_2 and not using NSCR.	Comply with any operating limitations approved by the Administrator.

■ 7. Table 2b to Subpart ZZZZ of Part 63 introductory text is revised to read as follows:

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing Compression Ignition Stationary RICE >500 HP, and Existing 4SLB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and compression ignition stationary RICE located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; existing compression ignition stationary RICE >500 HP; and existing 4SLB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

* * * * *

■ 8. Table 5 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations and Operating Limitations

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS.	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce CO emissions and not using oxidation catalyst.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Limit the concentration of CO, and not using oxidation catalyst.	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Limit the concentration of CO, and using a CEMS.	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce formaldehyde emissions and using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce formaldehyde emissions and not using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Limit the concentration of formaldehyde and not using NSCR.	i. The average formaldehyde concentration determined from the initial performance test is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
11. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP.	a. Reduce CO or formaldehyde emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
13. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP.	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.

■ 9. Table 6 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, Operating Limitations, Work Practices, and Management Practices

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP.	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved; [a] and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP.	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved; [a] and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP, existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS.	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and using NSCR.	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and not using NSCR.	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP.	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit; [a] and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit; [a] and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year.	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE.	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using oxidation catalyst or NSCR.	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE.	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using oxidation catalyst or NSCR.	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year.	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR.	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year.	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using an oxidation catalyst or NSCR.	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[FR Doc. 2011–5196 Filed 3–8–11; 8:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2011–0117; FRL–8863–2]

Potassium Benzoate; Exemption From the Requirement of a Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes an exemption from the requirement of a tolerance for residues of potassium benzoate (Cas No. 582–25–2) under 40 CFR 180.910 when used as an inert ingredient (preservative) in pesticide formulations applied to growing crops and raw agricultural commodities after harvest, and under 40 CFR 180.930 when used as an inert ingredient (preservative) in pesticide formulations applied to animals (used for food). Landis International, on behalf of Whitmire Micro-Gen submitted two petitions to EPA under the Federal Food, Drug, and Cosmetic Act (FFDCA), requesting establishment of an exemption from the requirement of a tolerance. This regulation eliminates the need to establish a maximum permissible level for residues of potassium benzoate.

DATES: This regulation is effective March 9, 2011. Objections and requests for hearings must be received on or before May 9, 2011, and must be filed in accordance with the instructions provided in 40 CFR part 178 (*see also* Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: EPA has established a docket for this action under docket identification (ID) number EPA–HQ–OPP–2011–0117. All documents in the docket are listed in the docket index available at *http://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 in the electronic docket at *http://www.regulations.gov*, or, if only available in hard copy, at the OPP Regulatory Public Docket in Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The Docket Facility is open from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket Facility telephone number is (703) 305–5805.

FOR FURTHER INFORMATION CONTACT: Elizabeth Fertich, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; *telephone number:* (703) 347–8560; *e-mail address: fertich.elizabeth@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. Potentially affected entities may include, but are not limited to:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

This listing is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in this unit could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether this action might apply to certain entities. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT**.

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of 40 CFR part 180 through the Government Printing Office's e-CFR site at *http://www.gpoaccess.gov/ecfr*.

C. How can I file an objection or hearing request?

Under FFDCA section 408(g), 21 U.S.C. 346a, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2011–0117 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing, and must be received by the Hearing Clerk on or before May 9, 2011. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing that does not contain any CBI for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit a copy of your non-CBI objection or hearing request, identified by docket ID number EPA–HQ–OPP–2011–0117, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the on-line instructions for submitting comments.
- *Mail:* Office of Pesticide Programs (OPP) Regulatory Public Docket (7502P), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001.
- *Delivery:* OPP Regulatory Public Docket (7502P), Environmental Protection Agency, Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. Deliveries are only accepted during the Docket Facility's normal hours of operation

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2008–0708, FRL–9190–3]

RIN 2060–AP36

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is promulgating national emission standards for hazardous air pollutants for existing stationary spark ignition reciprocating internal combustion engines that either are located at area sources of hazardous air pollutant emissions or that have a site rating of less than or equal to 500 brake horsepower and are located at major sources of hazardous air pollutant emissions.

DATES: This final rule is effective on October 19, 2010.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2008–0708. EPA also relies on materials in Docket ID Nos. EPA–HQ–OAR–2002–0059, EPA–HQ–OAR–2005–0029, and EPA–HQ–OAR–2005–0030 and incorporates those dockets into the record for this final rule. All documents in the docket are listed on the *http://www.regulations.gov* Web site. 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 *http://www.regulations.gov* or in hard copy at the EPA Headquarters Library, Room Number 3334, EPA West Building, 1301 Constitution Ave., NW., Washington, DC. The EPA/DC Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket and Information Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Melanie King, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541–2469; facsimile number (919) 541–5450; e-mail address *king.melanie@epa.gov*.

SUPPLEMENTARY INFORMATION:

Background Information Document. On March 5, 2009 (71 FR 9698), EPA proposed national emission standards for hazardous air pollutants (NESHAP) for existing stationary reciprocating internal combustion engines (RICE) that either are located at area sources of hazardous air pollutants (HAP) emissions or that have a site rating of less than or equal to 500 brake horsepower (HP) and are located at major sources of HAP emissions. A summary of the public comments on the proposal and EPA's responses to the comments, as well as the Regulatory Impact Analysis Report, are available in Docket ID No. EPA–HQ–OAR–2008–0708.

Organization of This Document. The following outline is provided to aid in locating information in the preamble.

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I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. General Information

A. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action include:

Category	NAICS [1]	Examples of regulated entities
Any industry using a stationary internal combustion engine as defined in this final rule.	2211	Electric power generation, transmission, or distribution.
	622110	Medical and surgical hospitals.
	48621	Natural gas transmission.
	211111	Crude petroleum and natural gas production.
	211112	Natural gas liquids producers.
	92811	National security.

[1] North American Industry Classification System.

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 engine is regulated by this action, you should examine the

applicability criteria of this final rule. 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.

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 this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by October 19, 2010. Under section 307(d)(7)(B) of the CAA, only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave., NW., Washington, DC 20460.

II. Background

This action promulgates NESHAP for existing stationary spark ignition (SI) RICE with a site rating of less than or equal to 500 HP located at major sources, and existing stationary SI RICE of any site rating located at area sources. EPA is finalizing these standards to meet its statutory obligation to address HAP emissions from these sources under sections 112(d), 112(c)(3) and 112(k) of the CAA. The final NESHAP for stationary RICE will be promulgated under 40 CFR part 63, subpart ZZZZ, which already contains standards applicable to new and reconstructed stationary RICE and some existing stationary RICE.

EPA promulgated NESHAP for existing, new, and reconstructed stationary RICE greater than 500 HP located at major sources on June 15, 2004 (69 FR 33474). EPA promulgated NESHAP for new and reconstructed stationary RICE that are located at area sources of HAP emissions and for new and reconstructed stationary RICE that have a site rating of less than or equal to 500 HP that are located at major sources of HAP emissions on January 18, 2008 (73 FR 3568). On March 3, 2010, EPA promulgated NESHAP for existing stationary compression ignition (CI) RICE with a site rating of less than or equal to 500 HP located at major sources, existing non-emergency CI engines with a site rating greater than 500 HP at major sources, and existing stationary CI RICE of any site rating located at area sources (75 FR 9674).

III. Summary of This Final Rule

A. What is the source category regulated by this final rule?

This final rule addresses emissions from existing stationary SI engines less than or equal to 500 HP located at major sources and all existing stationary SI engines located at area sources. A major source of HAP emissions is generally a stationary source that emits or has the potential to emit 10 tons per year or more of any single HAP or 25 tons per year or more of any combination of HAP. An area source of HAP emissions is a stationary source that is not a major source.

This action revises the regulations at 40 CFR part 63, subpart ZZZZ. Through this action, we are adding to 40 CFR part 63, subpart ZZZZ requirements for: existing SI stationary RICE less than or equal to 500 HP located at major sources of HAP and existing SI stationary RICE located at area sources of HAP.

1. Existing Stationary SI RICE ≤ 500 HP at Major Sources of HAP

This action revises 40 CFR part 63, subpart ZZZZ, to address HAP emissions from existing stationary SI RICE less than or equal to 500 HP located at major sources of HAP. For stationary engines less than or equal to 500 HP at major sources, EPA must determine what is the appropriate maximum achievable control technology (MACT) for those engines under sections 112(d)(2) and (d)(3) of the CAA.

EPA has divided stationary SI RICE less than or equal to 500 HP located at major sources of HAP into the following subcategories:

- Non-emergency 2-stroke lean burn (2SLB) stationary SI RICE 100–500 HP;
- Non-emergency 4-stroke lean burn (4SLB) stationary SI RICE 100–500 HP;
- Non-emergency 4-stroke rich burn (4SRB) stationary SI RICE 100–500 HP;
- Non-emergency landfill and digester gas stationary SI RICE 100–500 HP;
- Non-emergency stationary SI RICE < 100 HP; and
- Emergency stationary SI RICE.

2. Existing Stationary SI RICE at Area Sources of HAP

This action revises 40 CFR part 63, subpart ZZZZ, in order to address HAP emissions from existing stationary SI RICE located at area sources of HAP. Section 112(d) of the CAA requires EPA to establish NESHAP for both major and area sources of HAP that are listed for regulation under CAA section 112(c). As noted above, an area source is a stationary source that is not a major source.

Section 112(k)(3)(B) of the CAA calls for EPA to identify at least 30 HAP that, as a result of emissions of area sources, pose the greatest threat to public health in the largest number of urban areas. EPA implemented this provision in 1999 in the Integrated Urban Air Toxics Strategy (64 FR 38715, July 19, 1999). Specifically, in the Strategy, EPA identified 30 HAP that pose the greatest potential health threat in urban areas, and these HAP are referred to as the "30 urban HAP." Section 112(c)(3) of the CAA requires EPA to list sufficient categories or subcategories of area sources to ensure that area sources representing 90 percent of the emissions of the 30 urban HAP are subject to regulation. EPA implemented these requirements through the Integrated Urban Air Toxics Strategy (64 FR 38715,

July 19, 1999). The area source stationary engine source category was one of the listed categories. A primary goal of the Strategy is to achieve a 75 percent reduction in cancer incidence attributable to HAP emitted from stationary sources.

Under CAA section 112(d)(5), EPA may elect to promulgate standards or requirements for area sources "which provide for the use of generally available control technologies or management practices by such sources to reduce emissions of hazardous air pollutants." Additional information on generally available control technologies (GACT) and management practices is found in the Senate report on the legislation (Senate report Number 101–228, December 20, 1989), which describes GACT as:

> * * * methods, practices and techniques which are commercially available and appropriate for application by the sources in the category considering economic impacts and the technical capabilities of the firms to operate and maintain the emissions control systems.

Consistent with the legislative history, EPA can consider costs and economic impacts in determining GACT, which is particularly important when developing regulations for source categories, like this one, that have many small businesses.

Determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. EPA also considers the standards applicable to major sources in the same industrial sector to determine if the control technologies and management practices are transferable and generally available to area sources. In appropriate circumstances, EPA may also consider technologies and practices at area and major sources in similar categories to determine whether such technologies and practices could be considered generally available for the area source category at issue. Finally, as EPA has already noted, in determining GACT for a particular area source category, EPA considers the costs and economic impacts of available control technologies and management practices on that category.

The urban HAP that must be regulated from stationary SI RICE to achieve the CAA section 112(c)(3) requirement to regulate categories accounting for 90 percent of the urban HAP are: 7 polycyclic aromatic hydrocarbons (PAH), formaldehyde, and acetaldehyde.

Similar to existing stationary SI RICE at major sources, EPA has also divided the existing stationary SI RICE at area sources into subcategories in order to properly take into account the differences between these engines. The subcategories for existing stationary SI RICE at area sources are as follows:

- Non-emergency 2SLB stationary SI RICE
- Non-emergency 4SLB stationary SI RICE
  - ≤500 HP
  - >500 HP that operate more than 24 hours per calendar year
  - >500 HP that operate 24 hours or less per calendar year
- Non-emergency 4SRB stationary SI RICE
  - ≤500 HP that operate more than 24 hours per calendar year
  - >500 HP that operate 24 hours or less per calendar year
- Non-emergency landfill and digester gas stationary SI RICE
- Emergency stationary SI RICE.

B. What are the pollutants regulated by this final rule?

This final rule regulates emissions of HAP. Available emissions data show that several HAP, which are formed during the combustion process or which are contained within the fuel burned, are emitted from stationary engines. The HAP which have been measured in emission tests conducted on SI stationary RICE include: Formaldehyde, acetaldehyde, acrolein, methanol, benzene, toluene, 1,3-butadiene, 2,2,4-trimethylpentane, hexane, xylene, naphthalene, PAH, methylene chloride, and ethylbenzene. EPA described the health effects of these HAP and other HAP emitted from the operation of stationary RICE in the preamble to 40 CFR part 63, subpart ZZZZ, published on June 15, 2004 (69 FR 33474). More detail on the health effects of these HAP and other HAP emitted from the operation of stationary RICE can be found in the Regulatory Impact Analysis (RIA) for this final rule. These HAP emissions are known to cause, or contribute significantly to air pollution, which may reasonably be anticipated to endanger public health or welfare.

For the standards being finalized in this action, EPA believes that previous determinations regarding the appropriateness of using formaldehyde and carbon monoxide (CO) both in concentration (parts per million (ppm)) levels as surrogates for HAP for stationary RICE are still valid. Consequently, EPA is promulgating CO or formaldehyde standards in order to regulate HAP emissions.

In addition to reducing HAP, the emission control technologies that will be installed on stationary RICE to reduce HAP will also reduce CO and VOC, and for rich burn engines will also reduce NO_X.

C. What are the final requirements?

1. Existing Stationary SI RICE ≤500 HP at Major Sources of HAP

The numerical emission standards that are being finalized in this action for existing stationary non-emergency SI RICE less than or equal to 500 HP located at major sources of HAP are shown in Table 1 of this preamble. The emission standards are in units of ppm by volume, dry basis (ppmvd).

TABLE 1—EMISSION STANDARDS FOR EXISTING STATIONARY SI RICE >500 HP LOCATED AT MAJOR SOURCES OF HAP

Subcategory	Except during periods of startup
2SLB Non-Emergency 100≤HP≤500	225 ppmvd CO at 15% O_2.
4SLB Non-Emergency 100≤HP≤500	47 ppmvd CO at 15% O_2.
4SRB Non-Emergency 100≤HP≤500	10.3 ppmvd formaldehyde at 15% O_2.
Landfill/Digester Gas Non-Emergency 100≤HP≤500	177 ppmvd CO at 15% O_2.

EPA is finalizing work practice standards for existing emergency stationary SI RICE less than or equal to 500 HP located at major sources of HAP and existing non-emergency stationary SI RICE less than 100 HP located at major sources of HAP. Existing stationary emergency SI RICE less than or equal to 500 HP located at major sources of HAP are subject to the following work practices:

- Change oil and filter every 500 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and none of the condemning limits are exceeded;
- Inspect spark plugs every 1,000 hours of operation or annually,

whichever comes first, and replace as necessary; and

• Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

Existing stationary non-emergency SI RICE less than 100 HP located at major sources of HAP that are not 2SLB stationary RICE are subject to the following work practices:

• Change oil and filter every 1,440 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and none of the condemning limits are exceeded;

• Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and

• Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.

Existing 2SLB stationary SI RICE less than 100 HP located at major sources of HAP are subject to the following work practices:

• Change oil and filter every 4,320 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and none of the condemning limits are exceeded;

• Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and

• Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.

Sources also have the option to use an oil change analysis program to extend the oil change frequencies specified above. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The analysis must be conducted at the same frequencies specified for changing the engine oil. If the condemning limits provided below are not exceeded, the engine owner or operator is not required to change the oil. If any of the condemning limits are exceeded, the engine owner or operator must change the oil within two days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within two days or before commencing operation, whichever is later. The condemning limits are as follows:

• Total Acid Number increases by more than 3.0 milligrams potassium hydroxide per gram from Total Acid Number of the oil when new; or

• Viscosity of the oil changes by more than 20 percent from the viscosity of the oil when new; or

• Percent water content (by volume) is greater than 0.5.

Pursuant to the provisions of 40 CFR 63.6(g), sources can also request that the Administrator approve alternative work practices.

2. Existing Stationary SI RICE at Area Sources of HAP

The numerical emission standards that EPA is finalizing for non-emergency 4SLB stationary SI RICE and non-emergency 4SRB stationary SI RICE located at area sources of HAP are shown in Table 2.

TABLE 2—NUMERICAL EMISSION STANDARDS FOR EXISTING NON-EMERGENCY 4SLB STATIONARY SI RICE >500 HP LOCATED AT AREA SOURCES OF HAP AND EXISTING NON-EMERGENCY 4SRB STATIONARY SI RICE >500 HP LOCATED AT AREA SOURCES OF HAP

Subcategory	Except during periods of startup
4SLB Non-Emergency >500 HP that operate more than 24 hours per calendar year.	47 ppmvd CO at 15% O_2 or 93% CO reduction.
4SRB Non-Emergency >500 HP that operate more than 24 hours per calendar year.	2.7 ppmvd formaldehyde at 15% O_2 or 76% formaldehyde reduction.

EPA is finalizing management practices for existing non-emergency 4SLB stationary SI RICE less than or equal to 500 HP located at area sources of HAP, existing non-emergency 4SLB stationary SI RICE greater than 500 HP located at area sources of HAP that operate 24 hours or less per calendar year, existing non-emergency 4SRB stationary SI RICE less than or equal to 500 HP located at area sources of HAP, existing non-emergency 4SRB stationary SI RICE greater than 500 HP located at area sources of HAP that operate 24 hours or less per calendar year, existing 2SLB non-emergency stationary SI RICE located at area sources of HAP, existing non-emergency landfill and digester gas stationary RICE located at area sources of HAP, and existing emergency stationary SI RICE located at area sources of HAP.

Existing non-emergency 4SLB and 4SRB stationary SI RICE less than or equal to 500 HP located at area sources of HAP and existing landfill or digester gas non-emergency stationary SI RICE located at area sources of HAP are subject to the following management practices:

• Change oil and filter every 1,440 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and none of the condemning limits are exceeded;

• Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and

• Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.

Existing stationary 2SLB non-emergency engines located at area sources of HAP are subject to the following management practices:

• Change oil and filter every 4,320 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and none of the condemning limits are exceeded;

• Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and

• Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.

Existing stationary emergency SI RICE located at area sources of HAP and existing non-emergency 4SLB and 4SRB stationary SI RICE greater than 500 HP located at area sources of HAP that operate 24 hours or less per calendar year are subject to the following management practices:

• Change oil and filter every 500 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and none of the condemning limits are exceeded;

• Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and

• Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

As discussed above for major sources, these sources may utilize an oil analysis program, as described above, to extend the specified oil change requirement specified above. Also, sources have the option to work with State permitting authorities pursuant to EPA's regulations at 40 CFR subpart E ("Approval of State Programs and Delegation of Federal Authorities") for approval of alternative management practices. 40 CFR subpart E implements section 112(l) of the CAA, which authorizes EPA to approve alternative State/local/tribal HAP standards or programs when such requirements are demonstrated to be no less stringent than EPA promulgated standards.

3. Startup Requirements

Existing stationary SI RICE less than or equal to 500 HP located at major sources of HAP and existing stationary SI RICE located at area sources of HAP must meet specific operational standards during engine startup. Engine startup is defined as the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engines with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state, or normal operation, including the catalyst. Owners and operators must minimize the engine's time spent at idle and minimize the engine's startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the engine must meet the otherwise applicable emission standards. These requirements will limit the HAP emissions during periods of engine startup. Pursuant to the provisions of 40 CFR 63.6(g), engines at major sources may petition the Administrator for an alternative work practice. An owner or operator of an engine at an area source can work with its State permitting authority pursuant to EPA's regulations at 40 CFR subpart E for approval of an alternative management practice. See 40 CFR subpart E (setting forth requirements for, among other things, equivalency by permit, rule substitution).

D. What are the operating limitations?

In addition to the standards discussed above, EPA is finalizing operating limitations for existing stationary non-emergency 4SLB and 4SRB RICE that are greater than 500 HP, located at an area source of HAP, and operated more than 24 hours per calendar year. Owners and operators of engines that are equipped with oxidation catalyst or non-selective catalytic reduction (NSCR) must maintain the catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test. If the engine is equipped with oxidation catalyst, owners and operators must also maintain the temperature of the stationary RICE exhaust so that the catalyst inlet temperature is between 450 and 1,350 degrees Fahrenheit (°F). If the engine is equipped with NSCR, owners and operators must maintain the temperature of the stationary RICE exhaust so that the NSCR inlet temperature is between 750 and 1,250 °F. Owners and operators may petition for a different temperature range; the petition must demonstrate why it is operationally necessary and appropriate to operate below the temperature range specified in this final rule (see 40 CFR 63.8(f)). Owners and operators of engines that are not using oxidation catalyst or NSCR must comply with any operating limitations approved by the Administrator.

E. What are the requirements for demonstrating compliance?

The following sections describe the requirements for demonstrating compliance under this final rule.

1. Existing Stationary SI RICE ≤ 500 at Major Sources of HAP

Owners and operators of existing stationary non-emergency SI RICE located at major sources that are less than 100 HP and existing stationary emergency SI RICE located at major sources must operate and maintain their stationary RICE and aftertreatment control device (if any) according to the manufacturer's emission-related written instructions or develop their own maintenance plan. The maintenance plan must specify how the work practices will be met and provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practices for minimizing emissions. Owners and operators of existing stationary non-emergency SI RICE located at major sources that are less than 100 HP and existing stationary emergency SI RICE located at major sources do not have to conduct any performance testing because they are not subject to numerical emission standards.

Owners and operators of existing stationary non-emergency SI RICE located at major sources that are greater than or equal to 100 HP and less than or equal to 500 HP must conduct an initial performance test to demonstrate that they are achieving the required emission standards.

2. Existing Stationary SI RICE at Area Sources of HAP

Owners and operators of existing stationary RICE located at area sources of HAP that are subject to management practices do not have to conduct any performance testing; they must develop a maintenance plan that specifies how the management practices will be met and provides to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practices for minimizing emissions. Owners and operators of existing 4SLB and 4SRB non-emergency stationary SI RICE that are greater than 500 HP, located at an area source of HAP, and operated more than 24 hours per calendar year must conduct an initial performance test to demonstrate compliance with the applicable emission limitations and must conduct subsequent performance testing every 8,760 hours of operation or 3 years, whichever comes first. Owners and operators of existing 4SLB and 4SRB non-emergency stationary SI RICE that are greater than 500 HP, located at an area source of HAP, and operated more than 24 hours per calendar year must continuously monitor and record the inlet temperature of the oxidation catalyst or NSCR and also take monthly measurements of the pressure drop across the oxidation catalyst or NSCR. If an oxidation catalyst or NSCR is not being used on the engine, the owner or operator must continuously monitor and record the operating parameters (if any) approved by the Administrator. As discussed in the March 3, 2010, final NESHAP for existing stationary CI RICE (75 FR 9648) and in section V.E., EPA is finalizing performance specification requirements in 40 CFR part 63, subpart ZZZZ for the continuous parametric monitoring systems used for continuous catalyst inlet temperature monitoring.

F. What are the reporting and recordkeeping requirements?

The following sections describe the reporting and recordkeeping requirements that are required under this final rule.

Owners and operators of existing stationary emergency SI RICE that do not meet the requirements for non-emergency engines are required to keep records of their hours of operation. Owners and operators of existing stationary emergency SI RICE must install a non-resettable hour meter on their engines to record the hours of operation of the engine.

Owners and operators of existing stationary SI RICE located at major sources that are subject to work practices and existing stationary SI RICE located at area sources that are subject to management practices are required to keep records that show that the work or management practices that are required are being met. These records must include, at a minimum: Oil and filter change dates and corresponding engine hours of operation (determined using hour meter, fuel consumption data, or other appropriate methods); inspection and replacement dates for spark plugs, hoses, and belts; and records of other emission-related repairs and maintenance performed.

In terms of reporting requirements, owners and operators of existing non-emergency stationary SI RICE greater than or equal to 100 HP and less than or equal to 500 HP located at major sources of HAP and existing non-emergency 4SLB and 4SRB stationary RICE greater than 500 HP located at area sources of HAP that operate more than 24 hours per calendar year must submit the notifications required in Table 8 of 40 CFR part 63, subpart ZZZZ, which lists the NESHAP General Provisions applicable to this rule. (40 CFR part 63, subpart A) These notifications include an initial notification, notification of performance test, and a notification of compliance for each stationary RICE which must comply with the specified emission limitations. Owners and operators of existing stationary non-emergency SI RICE greater than or equal to 100 HP and less than or equal to 500 HP located at major sources of HAP and existing stationary 4SLB and 4SRB non-emergency SI RICE greater than 500 HP located at area sources of HAP that operate more than 24 hours per calendar year must submit semiannual compliance reports.

IV. Summary of Significant Changes Since Proposal

A. Applicability

A change from the proposal is that this final rule is not applicable to existing stationary emergency engines at area sources that are located at residential, commercial, or institutional facilities. These engines are not subject to any requirements under this final rule because they are not part of the regulated source category. EPA has found that existing stationary emergency engines located at residential, commercial, and institutional facilities that are area sources were not included in the original Urban Air Toxics Strategy inventory and were not included in the listing of urban area sources. More information on this issue can be found in the memorandum titled, "Analysis of the Types of Engines Used to Estimate the CAA Section 112(k) Area Source Inventory for Stationary Reciprocating Internal Combustion Engines," available from the rulemaking docket. In the March 3, 2010, final NESHAP for existing stationary CI RICE (75 FR 9648), EPA included a definition for residential/commercial/institutional emergency stationary RICE. After the final rule was promulgated, EPA received numerous questions regarding the definition and whether certain types of facilities would meet the definition. In this final rule, EPA is separating the definition into individual definitions for residential emergency stationary RICE, commercial emergency stationary RICE, and institutional emergency stationary RICE, and is also providing additional examples of the types of facilities that would be included under those categories in the definitions. EPA has also prepared a memorandum to provide further guidance regarding the types of facilities that would or would not be considered residential, commercial, or institutional facilities. The memorandum is titled, "Guidance Regarding Definition of Residential, Commercial, and Institutional Emergency Stationary RICE in the NESHAP for Stationary RICE," and is available in the rulemaking docket.

B. Final Emission Standards

1. Existing Stationary SI Engines ≤500 HP Located at Major Sources of HAP

EPA is revising the emission standards that it proposed for the subcategories of stationary SI engines less than or equal to 500 HP located at major sources. As discussed in section V.B., numerous commenters indicated that EPA's dataset used to establish the proposed emission limits was insufficient and urged EPA to gather more data to obtain a more complete representation of emissions from existing stationary SI engines. Commenters also questioned the emission standard setting approach that EPA used at proposal and claimed that the proposed standards did not take into account emissions variability. For this final rule, EPA has obtained additional test data for existing stationary SI engines and has included this additional data in the MACT floor analysis. EPA is also using an approach that better considers emissions variability, as discussed in V.B. below. EPA is also not using the Population Database to determine a percentage of engines that have emission controls installed, as it did at proposal. The Population Database has not been updated since 2000. It contains information regarding whether or not an engine has emission controls, but does not generally contain other types of emission-related information, like engine-out emissions or operational controls, and it does not include any emissions concentration data, which is necessary to determine the MACT floor. EPA determined that it would be more appropriate and more defensible to base the MACT floor analysis directly on the emissions data that EPA has for stationary SI engines, including data that was not used in the proposal. A more detailed discussion of both EPA's MACT floor and beyond-the-MACT-floor analysis can be found in the memorandum titled "MACT Floor and MACT Determination for Existing Stationary SI RICE ≤ 500 HP Located at Major Sources".

For 2SLB non-emergency engines, EPA proposed a limit of 85 ppmvd CO for engines from 50 to 249 HP and 8 ppmvd CO or 90 percent CO reduction for engines greater than or equal to 250 HP. EPA is finalizing an emission limit of 225 ppmvd CO for 2SLB non-emergency engines from 100 to 500 HP. For 4SLB non-emergency engines, EPA proposed a limit of 95 ppmvd CO for engines from 50 to 249 HP and 9 ppmvd CO or 90 percent CO reduction for engines greater than or equal to 250 HP. EPA is finalizing an emission limit of 47 ppmvd CO for 4SLB non-emergency engines from 100 to 500 HP. For 4SRB non-emergency engines from 50 to 500 HP, EPA proposed an emission limit of 200 ppbvd (parts per billion by volume, dry basis) formaldehyde or 90 percent formaldehyde reduction. EPA is finalizing an emission limit of 10.3 ppmvd formaldehyde for 4SRB non-emergency engines from 100 to 500 HP.

For landfill and digester gas engines, EPA proposed an emission limit of 177 ppmvd CO; EPA is finalizing an emission limit of 177 ppmvd CO.

For the proposed rule, EPA required existing stationary engines less than 50 HP that are located at major sources to meet a formaldehyde emission standard. As discussed in the final rule published on March 3, 2010, for existing stationary CI RICE (75 FR 9674), EPA is not finalizing a formaldehyde emission standard for stationary SI engines less than 50 HP, but is instead requiring compliance with work practices. In addition, in light of several comments asserting that the level at which EPA subcategorized small engines at major sources was inappropriate, EPA is finalizing a work practice standard for engines less than 100 HP. These work practices are described in section III.C. of this preamble. EPA believes that work practices are appropriate and justified for this group of stationary engines because the application of measurement methodology is not practicable due to technological and economic limitations. Further information on EPA's decision can be found in the memorandum titled, "MACT Floor and MACT Determination for Existing Stationary Non-Emergency SI RICE < 100 HP and Existing Stationary Emergency SI RICE Located at Major Sources and GACT for Existing Stationary SI RICE Located at Area Sources," which is available from the rulemaking docket.

For existing stationary emergency engines located at major sources, EPA proposed that these engines be subject to a 2 ppmvd formaldehyde emission standard. In this final rule, existing stationary emergency SI engines located at major sources of HAP must meet work practices. These work practices are described in section III.C. of this preamble. EPA believes that work practices are appropriate and justified for this group of stationary engines because the application of measurement methodology is not practicable due to technological and economic limitations. Further information on EPA's decision can be found in the memorandum titled, "MACT Floor and MACT Determination for Existing Stationary Non-Emergency SI RICE <100 HP and Existing Stationary Emergency SI RICE Located at Major Sources and GACT for Existing Stationary SI RICE Located at Area Sources," which is available from the rulemaking docket.

2. Existing Stationary SI Engines Located at Area Sources of HAP

EPA proposed numerical emission standards for the following stationary SI engines located at area sources of HAP: non-emergency 2SLB and 4SLB greater than or equal to 250 HP, non-emergency 4SRB greater than or equal to 50 HP, landfill and digester gas fired greater than 500 HP, and emergency greater than 500 HP. For the remaining engines at area sources, EPA proposed management practice standards.

In this final rule, EPA is promulgating numerical emission standards for non-emergency 4SLB and 4SRB stationary SI RICE larger than 500 HP located at area sources of HAP emissions that operate more than 24 hours per calendar year. For non-emergency 4SLB engines greater than 500 HP located at area sources of HAP, EPA proposed an emission limit of 9 ppmvd CO or 90 percent CO reduction; EPA is finalizing an emission limit of 47 ppmvd CO or 93 percent CO reduction. For non-emergency 4SRB engines greater than 500 HP located at area sources of HAP, EPA proposed an emission limit of 200 ppbvd formaldehyde or 90 percent formaldehyde reduction and is finalizing an emission limit of 2.7 ppmvd formaldehyde or 76 percent formaldehyde reduction. For stationary SI RICE located at area sources of HAP that are non-emergency 2SLB stationary SI RICE greater than or equal to 250 HP, non-emergency 4SLB stationary SI RICE between 250 and 500 HP, non-emergency 4SRB stationary SI RICE between 50 and 500 HP, landfill/digester gas stationary SI RICE greater than 500 HP, or emergency stationary SI RICE greater than 500 HP, EPA is finalizing management practices rather than numeric emission limitations as proposed. EPA is also finalizing management practices for non-emergency 4SLB and 4SRB stationary SI RICE that are greater than 500 HP, located at area sources of HAP, and operated 24 hours or less per calendar year.

C. Management Practices

EPA proposed management practices for several subcategories of engines located at area sources. EPA explained that the proposed management practices would be expected to ensure that emission control systems are working properly and would help minimize HAP emissions from the engines. EPA proposed specific maintenance practices and asked for comments on the need and appropriateness for those procedures. Based on feedback received during the public comment period, which included information submitted in comment letters and additional information EPA received following the close of the comment period from different industry groups, EPA is finalizing management practices for existing stationary 2SLB non-emergency SI engines located at area sources of HAP, existing stationary 4SLB and 4SRB non-emergency SI engines less than or equal to 500 HP located at area sources of HAP; existing stationary landfill and digester gas non-emergency engines located at area sources of HAP; and existing emergency stationary SI engines located at area sources of HAP.

Based on the comments on the proposal and additional information received from stakeholders, EPA made changes to the intervals for the management practices from the proposal. EPA is also adding an option for sources to use an oil change analysis program to extend the oil change frequencies specified above. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. If the condemning limits for these parameters are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within two days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within two days or before commencing operation, whichever is later. Owners and operators of all engines subject to management practices also have the option to work with State permitting authorities pursuant to EPA's regulations at 40 CFR subpart E for alternative management practices to be used instead of the specific management practices promulgated in this final rule. The management practices must be at least as stringent as those specified in this final rule.

D. Startup, Shutdown, and Malfunction

EPA proposed formaldehyde and CO emission standards for existing stationary engines at major sources to apply during periods of startup and malfunction. EPA also proposed certain standards for existing stationary engines at area sources that would apply during startup and malfunction. EPA did not propose distinct standards for periods of shutdown. EPA proposed that engines would be subject to the same standards during shutdown as are applicable during other periods of operation.

Based on various comments and concerns with the proposed emission standards for periods of startup, EPA has determined that it is not feasible to finalize numerical emission standards that would apply during startup because the application of measurement methodology to this operation is not

practicable due to technological and economic limitations. This issue is discussed in detail in the final rule published on March 3, 2010 (75 FR 9674), and as discussed in the Response to Comments for this rule, the analysis is the same for the engines regulated in this final rule.

As a result, EPA is extending the operational standards during startup it promulgated in the March 3, 2010, final rule (75 FR 9674), which specify that owners and operators must limit the engine startup time to no more than 30 minutes and must minimize the engine's time spent at idle during startup, to the engines newly subject to regulation in this rule.

With respect to malfunctions, EPA proposed two options for subcategories where the proposed emission standard was based on the use of catalytic controls. The first proposed option was to have the same standards apply during normal operation and malfunctions. The second proposed option was that standards during malfunctions be based on emissions expected from the best controlled sources prior to the full warm-up of the catalytic control. For subcategories where the proposed emission standard was not based on the use of catalytic controls, we proposed the same emission limitations apply during malfunctions and periods of normal operations. EPA is finalizing the first option described above, which is that the same standards apply during normal operation and malfunctions. In the proposed rule, EPA expressed the view that there are different modes of operation for any stationary source, and that these modes generally include startup, normal operations, shutdown, and malfunctions. However, as discussed in detail in the final rule published on March 3, 2010 (75 FR 9674), and as discussed in the Response to Comments for this rule, after considering the issue of malfunctions more carefully, EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. In addition, as discussed in detail in the final rule published on March 3, 2010 (75 FR 9674), and as discussed in the Response to Comments for this rule, EPA believes that malfunctions will not cause stationary engines to violate the standard that applies during normal operations. Therefore, the standards that apply during normal operation also apply during malfunction.

E. Method 323

EPA proposed to remove Method 323 as an option for determining compliance with formaldehyde emission limitations in 40 CFR part 63, subpart ZZZZ. EPA Method 323 was first proposed as part of the NESHAP for Stationary Combustion Turbines published January 14, 2003, (68 FR 1888) for measuring formaldehyde emissions from natural gas-fired sources. However, the method was not included in the final Stationary Combustion Turbines NESHAP due to reliability concerns and EPA never promulgated EPA Method 323 as a final standard in 40 CFR part 63, appendix A. Due to unresolved technical issues with the method affecting engine test results, EPA found it appropriate to propose to remove the method from 40 CFR part 63, subpart ZZZZ. As discussed in greater detail in section V.D., after EPA proposed to remove Method 323 as a compliance test Method, the Agency received test data comparing Method 323 to EPA Method 320. The results of this comparison testing showed good agreement between the two methods and there was no evidence of bias in the results from Method 323. Therefore, EPA has determined that it is appropriate to promulgate Method 323 and to allow it as an option for measuring formaldehyde in 40 CFR part 63, subpart ZZZZ.

F. Other

EPA is making several minor clarifications to this final rule to address comments that the provisions were confusing and difficult for affected sources to understand. One clarification is to individually list out the engines discussed in 40 CFR 63.6590(b)(3) and (c) instead of having them in a single paragraph. The definition of emergency stationary RICE and the provisions for emergency stationary RICE in 40 CFR 63.6640(f) have been reorganized in order to provide more clarity regarding those provisions and to more clearly specify that all emergency stationary RICE must comply with the requirements specified in 40 CFR 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in 40 CFR 63.6640(f), then it is not considered to be an emergency stationary RICE. Minor clarifications have also been made to the tables to provide additional clarification on the applicability of the requirements in the tables.

V. Summary of Responses to Major Comments

A. Applicability

Comment: Numerous commenters expressed concern over EPA's decision to not distinguish between rural and urban engines at area sources in the proposed rule. Several commenters requested that EPA reevaluate its congressional authority to regulate area HAP sources in rural areas. The commenters believed that the proposal is inconsistent with 42 U.S.C. 7412(n)(4)(B) [CAA section 112(n)(4)(B)]. Commenters requested clarification of EPA's rationale to regulate low levels of emissions from engines at oil and gas production facilities outside metropolitan areas, contending that EPA has applied this rule more broadly than the Congressional intent of the CAA, and requested that EPA reevaluate this issue of whether EPA can regulate rural area sources in light of the 42 U.S.C. 7412(n)(4)(B) language.

Commenters stated that EPA has based this rulemaking for area sources on sections of the CAA and its Urban Air Toxics Strategy that are intended to remove threats to public health in urban areas. The commenters do not believe that the remote RICE at area sources in the oil and gas industry threaten public health in urban areas. Several commenters noted that the NESHAP for glycol gas dehydrators (40 CFR part 63, subpart HH) takes into account the location of area sources and does not apply the specific requirements of the rule to rural area sources. The commenters believe that the same approach should be used for the RICE rule, *i.e.*, engines that are not located in or near populated areas should be subject to an alternative set of requirements so as not to force expensive requirements on remote engines that have no impact on public health.

Response: EPA is finalizing its proposal to regulate existing stationary SI engines located at area sources on a nationwide basis. EPA believes that the CAA provides the Agency with the authority to regulate area sources nationwide. Section 112(k)(1) of the CAA states that "It is the purpose of this subsection to achieve a substantial reduction in emissions of hazardous air pollutants from area sources and an equivalent reduction in the public health risks associated with such sources including a reduction of not less than 75 per centum in the incidence of cancer attributable to emissions from such sources." Consistent with this expressed purpose of section 112(k) of

the CAA to reduce both emissions and risks, CAA section 112(k)(3)(i) requires that EPA list not less than 30 HAP that, as a result of emissions from area sources, present the greatest threat to public health in the largest number of urban areas. Sections 112(c)(3) and (k)(3)(ii) of the CAA require that EPA list area source categories that represent not less than 90 percent of the area source emissions of each of the listed HAP. Section 112(c) of the CAA requires that EPA issue standards for listed categories under CAA section 112(d). These relevant statutory provisions authorize EPA to regulate listed area source engines and not just engines located in urban areas. EPA believes that sections 112(c) and 112(k) of the CAA do not prohibit issuing area source rules of national applicability. EPA also disagrees with the statement that the proposal was inconsistent with section 112(n)(4)(B) of the CAA. The term "associated equipment" was defined for the purposes of 40 CFR part 63, subpart ZZZZ in the first RICE MACT rule not to include stationary RICE. EPA has not revisited that issue in this final rule and the commenters have not provided sufficient reason to revisit that issue.

EPA has taken steps in the final rule that reduce the burden on owners and operators of engines regulated in this final rule. EPA has established management practice standards for most of the engines located at area sources of HAP. The only existing stationary SI RICE at area sources that are required to meet numeric emission limitations are 4SLB and 4SRB non-emergency stationary SI RICE that are greater than 500 HP and operate more than 24 hours per calendar year; these engines are estimated to be only 7 percent of the population of existing SI RICE at area sources. EPA believes that requiring management practices instead of specific emission limitations and/or control efficiency requirements on the vast majority of existing stationary SI engines at area sources alleviates concerns regarding costly and burdensome requirements for rural sources.

EPA has also determined that existing emergency engines located at residential, institutional, and commercial facilities that are area sources of HAP emissions were not included in the original Urban Air Toxics Strategy inventory and therefore are not included in the source category listing. In this final rule, EPA has specified that those engines are not subject to 40 CFR part 63, subpart ZZZZ. EPA has clarified the definitions of these existing emergency engines in this final rule. As further clarification, EPA notes that existing emergency engines located at, among other things, industrial facilities, would not be affected by this determination and are subject to 40 CFR part 63, subpart ZZZZ.

For existing stationary 4SLB and 4SRB non-emergency SI engines greater than 500 HP located at area sources that operate more than 24 hours per calendar year, EPA determined that the appropriate standards are numerical standards that provide for the use of oxidation catalyst or NSCR control, respectively, which are generally available control technologies for those subcategories. The commenters did not provide a reason that GACT would be different for non-emergency stationary SI engines located in rural areas. In determining GACT, EPA can consider factors such as availability and feasibility of control technologies and management practices, as well as costs and economic impacts. These factors are not expected to be significantly different for existing stationary non-emergency SI engines in urban versus rural areas. For example, the availability of oxidation catalysts would be the same for urban and rural engines, and if an engine was in a rural location, that would not preclude an owner from being able to install aftertreatment controls. For this final rule, EPA estimated the capital cost of retrofitting an existing stationary 4SLB non-emergency SI engine with an oxidation catalyst to be around $9,500 for a 500 HP engine. Annual costs of operating and maintaining the control device are estimated to be approximately $4,300 per year for the same engine. For a 500 HP 4SRB engine, EPA estimated the costs for NSCR are a capital cost of $26,000 and an annual cost of $8,000. These costs would not be prohibitive for any engines in either rural or urban areas and are expected to be the same no matter the location. Furthermore, the controls that are expected to be used on these engines will have the co-benefit of reducing VOC and CO emissions and, for non-emergency 4SRB engines above 500 HP will have the co-benefit of reducing NO_X emissions. This final rule is expected to reduce emissions of NO_X from stationary SI RICE located at area sources by 96,000 tons per year (tpy) in the year 2013. Reductions of CO and VOC from stationary SI RICE located at area sources are estimated to be 97,000 and 24,000 tpy, respectively, in the year 2013. There is also no reason to distinguish between the rural and urban area source engines that are subject to management practices. There is nothing limiting owners and operators of existing stationary SI engines located in rural areas from following the management practices specified in this final rule, and the management practices required by this final rule are appropriate for all engines, whether they are in rural or urban locations.

Consistent with the proposal and for the reasons discussed, EPA is finalizing national requirements for existing stationary SI engines at area sources without a distinction between urban and non-urban areas.

B. Emission Standards

Comment: Multiple commenters were concerned with how EPA set the MACT floor for the proposed rule. The commenters believed that the emissions data was not adequate to conduct a MACT floor analysis. Several commenters said that EPA has not considered variability in setting the MACT floor for the proposed rule. A commenter cited the recent Brick MACT ruling which indicated that "floors may legitimately account for variability [in the best performing sources that are the MACT floor basis] because "each [source] must meet the [specified] standard every day and under all operating conditions." The commenters stated EPA's data set is not sufficient in covering variability. One commenter noted that the Courts have been critical of EPA's process for setting minimum allowable emission limits. The commenter stated that EPA set the emission limits by averaging the best 12 percent of all performance tests for each subcategory, but did not consider operational variations of the units. The commenter recommended that EPA set emission limits at the emissions level that is actually achieved under the worst reasonably foreseeable circumstances for the best performing 12 percent of existing sources.

Response: The CAA requires EPA to set MACT standards based on the test data that is available to the Agency and this is what EPA did at proposal. EPA recognized that it had limited emissions test data at the time it was developing the proposed rule. However, EPA had requested additional test data to supplement the emissions database from commenters during the development of previous rules for stationary engines. In addition, EPA requested additional test data during the comment period for the current engine rulemaking. EPA made an additional effort post-proposal to reach out to industry and other sources in order to supplement the existing emission data set. EPA received data for an additional 619 engines during the post-proposal period; this data was incorporated into the MACT floor

analysis for this final rule. EPA also identified additional emissions data for stationary 4SLB SI RICE that was in the docket for the original RICE NESHAP rulemaking, docket EPA–HQ–OAR–2002–0059. These data were inadvertently omitted from the MACT floor analysis for the proposed rule, but have been incorporated into the analysis for the final rule, along with the additional emissions data received post-proposal. EPA placed all additional data into the docket for this rule. Stakeholders who believe that further review of this information is in order or necessary can petition for reconsideration of this final rule.

The U.S. Court of Appeals for the D.C. Circuit has recognized that EPA may consider variability in estimating the degree of emission reduction achieved by best-performing sources and in setting MACT floors. *See Mossville Envt'l Action Now* v. *EPA,* 370 F.3d 1232, 1241–42 (D.C. Cir 2004). EPA has included a revised approach to variability in the MACT floor analysis for this final rule. The final emission standards are based on test data collected from stationary engines produced by different engine manufacturers, operating at various loads and other conditions, and located in various types of service and locations. The engines range in size from 39 HP to 12,000 HP. The data includes engines operating at loads from 11 to 100 percent. To the extent commenters believed further data would have been beneficial to EPA, EPA must make its determinations based on the information available to us. EPA asked for further data, and EPA did receive further data following the proposal, which led to changes in the final regulations. For engines operating at reduced speed or loads resulting in a reduced exhaust temperature, EPA believes that numerical emission requirements are still appropriate and there is no justification to only require work practice standards during these situations. EPA does not believe that the provisions of section 112(h) of the CAA are met (except as discussed elsewhere with regard to periods of start-up, emergency engines, and engines below 100 HP) because testing is not economically and technologically impractical and the emissions can be readily routed through a conveyance for purposes of emission testing. EPA believes that the final emission standards will reflect the numerous engine models and operating scenarios that can be expected from stationary engines.

In order to determine the MACT floor for each subcategory, EPA ranked all of the sources for which it had data based on their emissions and identified the lowest emitting 12 percent of the sources based on the lowest test for each engine. EPA used all of the emissions data for those best performing engines to determine the emission limits for this final rule, accounting for variability. EPA notes that as a result of using emissions testing data directly to determine the MACT, rather than using the Population Database, the final MACT floor for 4SLB engines was calculated using data from engines with emissions aftertreatment, which were the best performing 12% of engines in the emissions database.

EPA assessed the variability of the best performers by using a statistical formula designed to estimate a MACT floor level that is achieved by the average of the best performing sources if the best performing sources were able to replicate the compliance tests in our data set. Specifically, the MACT floor limit is an upper prediction limit (UPL) calculated with the Student's t-test using the TINV function in Microsoft Excel. The Student's t-test has also been used in other EPA rulemakings (*e.g.,* New Source Performance Standards for Hospital/Medical/Infectious Waste Incinerators, Proposed NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters) in accounting for variability. A prediction interval for a future observation is an interval that will, with a specified degree of confidence, contain the next (or some other pre-specified) randomly selected observation from a population. In other words, the prediction interval estimates what future values will be, based upon present or past background samples taken. Given this definition, the UPL represents the value which EPA can expect the mean of 3 future observations (3-run average) to fall below, based upon the results of an independent sample from the same population. In other words, if EPA were to randomly select a future test condition from any of these sources (*i.e.,* average of 3 runs), EPA can be 99 percent confident that the reported level will fall at or below the UPL value. To calculate the UPL, EPA used the average (or sample mean) and sample standard deviation, which are two statistical measures calculated from the sample data. The average is the central value of a data set, and the standard deviation is the common measure of the dispersion of the data set around the average. This approach reasonably ensures that the emission limit selected as the MACT floor adequately represents the level of emissions actually achieved by the average of the units in the top 12 percent, considering ordinary operational variability of those units. Both the analysis of the measured emissions from units representative of the top 12 percent, and the variability analysis, are reasonably designed to provide a meaningful estimate of the average performance, or central tendency, of the best controlled 12 percent of units in a given subcategory.

Comment: Commenters stated that EPA should reevaluate its GACT determinations for engines located at area sources. Commenters stated that EPA is not required to consider the MACT floor as a minimum standard for area sources, but may instead elect to promulgate standards or requirements for area sources which provide for the use of GACT or management practices by such sources to reduce emissions of HAP. The commenters stated that EPA must consider not only the economic impacts and whether the methods, practices, and techniques are commercially available and appropriate for application by the sources in the category, but also the technical capabilities of the firms to operate and maintain the emissions controls systems. The commenters pointed out that unlike engines located at major sources, which are often large industrial facilities, many engines at area sources are owned and operated by small businesses with little or no experience dealing with complex regulatory issues and with minimal technical and financial resources. Commenters said that EPA's GACT determination for engines located at area sources does not adequately account for the variation in engines that would be covered under the proposed control requirements when applied to area sources. The commenters listed several factors (engine size, cost effectiveness of control devices, engine usage and duty cycles, engine location) that must be considered in assessing whether and to what degree existing engines at area sources should be regulated. Commenters recommended defining a size based subcategory for area sources for natural gas-fired 4SRB engines similar to the size threshold used for CI engines. The commenters recommended that the subcategory or subcategories would require GACT management practices rather than emission standards based on catalytic control. At a minimum, the commenters recommended that subcategories be included in the proposed rule for rural area source natural gas-fired 4SRB engines from 50 HP to 500 HP.

Response: EPA has reviewed its proposed requirements for existing SI engines at area sources based on comments received on the proposed rule. For existing non-emergency 4SRB and 4SLB stationary SI RICE greater than 500 HP at area sources that operate more than 24 hours per calendar year, EPA determined for the final rule that it is appropriate to set numerical emission limits that EPA expects would be met using emission control technologies. The costs and economic impacts are reasonable and the control technologies that would be expected to be used are generally available for these area source engines.

For the remaining existing stationary SI RICE at area sources, the final rule requires management practices. EPA received comments and supporting information indicating that EPA had underestimated the cost of emission controls and overestimated how many engines were already using these controls. EPA reevaluated the cost impacts associated with establishing numeric emission limitations for these engines and determined that the cost impacts would be unreasonable given the expected emission impacts both with and without the expectation of use of emission control technologies. For example, for 4SRB engines, the annual cost per ton of HAP reduced, assuming the engine will have to install emission controls to meet the emission limit, is estimated to be $762,000 for a 50 HP engine and $167,000 for a 250 HP engine. For 2SLB and 4SLB engines at 250 HP, the annual cost per ton of HAP reduced is estimated to be $224,000 and $55,000, respectively, assuming the engines will have to install emission controls to meet the emission limit. Engine owners/operators have indicated that most of these smaller area source engines are not equipped with the control technologies required to meet these limits. Based on this information, EPA determined that management practices for these stationary SI RICE located at area sources of HAP are generally available and cost effective and is promulgating management practices for these engines in the final rule. Additional information regarding this determination can be found in the memorandum titled, "MACT Floor and MACT Determination for Existing Stationary Non-Emergency SI RICE <100 HP and Existing Stationary Emergency SI RICE Located at Major Sources and GACT for Existing Stationary SI RICE Located at Area Sources," which is available from the rulemaking docket.

C. Management Practices

Comment: Several commenters did not agree with the specific management practices that EPA proposed in the rule for area sources and recommended different maintenance practices. According to the commenters, the maintenance frequency in the proposed rule exceeds current practices or is not supported in the proposed rule. Several commenters agreed that management practices are appropriate for the proper operation of the engines and are a reasonable means to reduce HAP emissions, however, the commenters did not agree with the specific maintenance practices proposed by EPA. Numerous commenters recommended that EPA allow owners/operators to follow engine manufacturers' recommended practices or the owners/operators own site-specific maintenance plan.

One commenter pointed out that operators have a direct interest in maintaining engine oil, hoses, and belts, so the engine runs reliably, but the appropriate frequency for these maintenance practices are specific to engine design and are not "one size fits all." Commenters recommended that EPA revise fixed maintenance (one-size-fits-all) requirements to maintenance plans. The commenters stated that, while fixed maintenance intervals work well for new mass produced engines similar to those in automobiles, they are inappropriate for the wide variety of existing engines used in the oil and gas, agriculture, and power generation industries across the nation. The commenters pointed out that EPA allows the use of operator-defined maintenance plans that are "consistent with good air pollution control practice for minimizing emissions" to be used in other portions of this same rule, and asserted that EPA should allow the use of operator-defined maintenance plans to greatly reduce cost and allow operators to optimize maintenance for each type of engine.

Commenters said that if EPA keeps the management practices as proposed, the frequencies associated with conducting engine maintenance should be revised to be commensurate with today's practices. The commenters believed the maintenance practices, as proposed, are significantly burdensome and lack basis. According to the commenters, EPA should replace the maintenance hour intervals with company recommended performance-based maintenance practices to be documented in an operator-defined maintenance plan consistent with requirements in 40 CFR part 60, subpart JJJJ.

One commenter stated that most of the engine manufacturers for the engines in the oil and gas industry recommend oil changes on a monthly schedule. The commenter also indicated that it is common practice to periodically sample and test the engine oil to see if the oil properties are sufficient to extend this time period between oil changes. According to the commenter, this testing has shown in many cases that the oil change interval can be extended without any detrimental effects on the engine, which allows industry to maximize efficiencies, minimize oil usage, reduce waste, and streamline operations with no negative impacts to the engine or emissions.

One commenter expressed that inspection of hoses and belts has no impact on HAP emissions. The commenter expressed that, generally, it agreed that performing maintenance on engines will help to reduce HAP emissions, but that while inspecting belts and hoses is an important part of general engine maintenance (and most sources likely conduct regular inspections of their engines), such inspections have no effect on emissions and should not be included in the final rule.

Response: EPA proposed to require specific management practices for certain engines, primarily for smaller existing stationary engines at area sources where EPA determined that add-on controls were not GACT. EPA indicated at proposal that the management practices specified in the proposal reflected GACT and that such practices would provide a reasonable level of control, while at the same time ensuring that the burden on particularly small businesses and individual owners and operators would be minimized. EPA asked for comment on the proposed management practices and received comments on the proposal from industry.

EPA agrees with the commenters that it is difficult to adopt a set of management practices that are appropriate for all types of stationary engines. Regardless, EPA must promulgate emission standards pursuant to section 112(d)(5) of the CAA for all engines at area sources covered by this final rule. EPA still believes that management practices reflect GACT for emergency engines, engines less than or equal to 500 HP, 2SLB engines, and landfill/digester gas engines at area sources. These management practices represent what is generally available among such engines to reduce HAP, and

the practices will ensure that emissions are minimized and engines are properly operated. EPA does not agree with the commenters that it would be appropriate to simply specify that owners and operators follow the manufacturer's recommended maintenance practices for the engine. EPA cannot delegate to manufacturers the final decision regarding the proper management practices required by section 112(d) of the CAA. To address the comments that there may be special and unique operating situations where the management practices in this final rule may not be appropriate, for example engines using a synthetic lubricant, EPA notes that owners/operators may work with State permitting authorities pursuant to 40 CFR subpart E ("Approval of State Programs and Delegation of Federal Authorities") for approval of alternative management practices for their engines. 40 CFR subpart E implements section 112(l) of the CAA, which authorizes EPA to approve alternative State/local/tribal HAP standards or programs when such requirements are demonstrated to be no less stringent than EPA promulgated standards.

The management practices EPA proposed for stationary SI engines greater than 50 HP included changing the oil and filter every 500 hours, replacing the spark plugs every 1,000 hours, and inspecting all hoses and belts every 500 hours and replacing as necessary. For engines less than 50 HP, EPA proposed to require that these engines change the oil and filter every 200 hours, replace spark plugs every 500 hours, and inspect all hoses and belts every 500 hours and replace as necessary.

EPA agrees that there is a wide range of recommended maintenance procedures, but EPA must promulgate specific requirements pursuant to section 112(d) of the CAA for this source category. Based on the different suggested maintenance recommendations EPA has reviewed, maintenance requirements appear to vary depending on whether the engine is used for standby, intermittent, or continuous operation. Maintenance is also dependent on the engine application, design, and model.

Taking into consideration the information received from commenters on the proposed maintenance practices for oil and filter changes and carefully reviewing engine manufacturer recommended maintenance procedures, EPA has determined that for stationary non-emergency 4SLB and 4SRB SI RICE at or below 500 HP and stationary non-emergency landfill/digester gas SI RICE, GACT will require the management practices to be performed every 1,440 hours of engine operation or annually, whichever comes first, which, as indicated in the comments, reflects the management practices that are generally available. For stationary non-emergency 2SLB SI RICE, GACT will require the management practices to be performed every 4,320 hours of engine operation or annually, whichever comes first. Two stroke lean burn engines have a longer maintenance interval than 4-stroke engines because they do not have combustion blow-by gases entering the crankcase due to the engine configuration and therefore do not have as much oil contamination from the combustion blow-by gases. The 2SLB engines also operate at lower speeds and temperatures than 4-stroke engines; consequently the spark plug does not fire as frequently and fires at lower temperatures than 4-stroke engines. For these reasons, EPA agrees that 2SLB engines should have longer maintenance practice intervals than 4-stroke engines. EPA also determined that it would be appropriate to include the option to use an oil analysis program in this final rule.

EPA does not agree with the comments that EPA's proposed requirement to inspect belts and hoses has no impact on emissions. Ensuring that the engine is properly operated and maintained will help minimize the HAP emissions from the engine. Properly maintained belts and hoses allow the engine to operate at maximum efficiency. Hoses are generally used to move coolant through the engine to prevent the engine from overheating. Overheating of the engine can cause a malfunction in the combustion process, and may also burn the engine oil in the combustion chamber. Both of these conditions may increase pollutant emissions from the engine. Belts are commonly used for electrical generation and engine timing, and if worn or broken can cause damage to the engine and increase emissions. Therefore, EPA has required management practices that reflect GACT and that, in EPA's view, will ensure the proper operation and maintenance of the engine.

D. Method 323

Comment: Many commenters thought that EPA should reconsider whether EPA Method 323 could be included in this final rule or if there is another viable alternative to EPA Method 320. EPA Method 323 was published in the **Federal Register** on January 14, 2003, as a proposed test method to measuring formaldehyde from natural gas stationary combustion sources, but the method was never finalized. However, the commenters said that the method has been used on a consistent basis to measure formaldehyde from gas engines for compliance and other purposes. EPA Region 8 has test results that indicate potential issues related to the reliability of EPA Method 323 and the method was therefore not included in the proposed rule. The commenters said that they believe that testing errors may have been a factor in the anomalous results from EPA Region 8. The commenters have reviewed some of the test reports in question and noted potential calculation or testing errors. The Fourier Transform Infrared method, which is the single formaldehyde test method in the proposal, compared to Method 323 is more complex and often more expensive, according to the commenters. In addition, several commenters have concerns about whether there will be a sufficient amount of available testing companies to meet the performance testing demands of this final rule. For these reasons, several of the commenters said that EPA should look back at Method 323 as a viable method and at the same time consider other alternatives for measuring formaldehyde.

Response: EPA Method 323 was first proposed as part of the NESHAP for Stationary Combustion Turbines published January 14, 2003, (68 FR 1888) for measuring formaldehyde emissions from natural gas-fired sources. However, the method was not included in the final Stationary Combustion Turbine NESHAP due to reliability concerns and EPA never promulgated EPA Method 323 as a final standard in 40 CFR part 63, appendix A. Despite this, many sources chose to use the method for compliance testing and as EPA reviewed the results from the method two issues emerged. A few testers seemed to produce results with the method that were consistently biased low, and occasionally testers were unable to meet the performance requirement for collecting duplicate samples whose results agreed within ± 20 percent. Because EPA was unable to resolve these technical issues with the method, EPA found it appropriate to propose to remove the method from 40 CFR part 63, subpart ZZZZ.

After EPA proposed to remove Method 323 as a compliance test method, the Agency received test data comparing Method 323 to EPA Method 320. These comparison tests were run on five different engines with samples collected concurrently from co-located sampling systems. The results from the two methods showed good agreement and there was no evidence of bias in the

results from Method 323. Also, during the comparison testing, there were no problems meeting the quality assurance requirement in Method 323 for agreement between duplicate samples. A careful review of the earlier data where some testers using Method 323 were consistently producing biased results showed that these testers did not always perform the method correctly. Based on the results of the comparison testing, EPA believes that when competent testers perform Method 323 according to all of its requirements, the method will produce accurate and consistent results and it is appropriate to allow sources the option to use Method 323 to demonstrate compliance with the formaldehyde emission limits in 40 CFR part 63 subpart ZZZZ. Therefore, we are adding Method 323 to Appendix A of Part 63 as part of this action.

E. Other

Comment: One commenter indicated that they had provided significant comments in February 2009 on EPA's Continuous Parameter Monitoring Systems proposal (73 FR 59956, October 9, 2008) and believes that extensive revisions are needed of Performance Specifications 17 and 4. The commenter asked that EPA review these procedures to determine their appropriateness for even larger engines and suggested that EPA remove the reference to 40 CFR 63.8(a)(2) from Table 8 of the proposed rule, *i.e.*, change "Yes" to "No" for this paragraph.

Response: EPA does not agree with the commenter that the reference to 40 CFR 63.8(a)(2) in Table 8 of the rule should be "no". The commenter did not provide any information to support the claim that the Performance Specifications and 40 CFR 63.8(a)(2) are not appropriate for stationary engines. In response to this comment, EPA reviewed the proposed Performance Specifications and determined that they are appropriate for stationary engines, including stationary SI engines. In order to clearly indicate the requirements from the Performance Specifications that should be followed for the stationary engines subject to this rulemaking, EPA has included the Performance Specification requirements in 40 CFR part 63 subpart ZZZZ.

VI. Summary of Environmental, Energy and Economic Impacts

A. What are the air quality impacts?

This final rule is expected to reduce total HAP emissions from stationary RICE by 6,000 tpy beginning in the year 2013, which is the first year this final rule will be implemented. EPA estimates that approximately 330,000 stationary SI engines will be subject to this final rule. These estimates include stationary engines located at major and area sources; however, not all stationary engines are subject to numerical emission standards. Further information regarding the estimated reductions of this final rule can be found in the memorandum titled, "Impacts Associated with NESHAP for Existing Stationary SI RICE," which is available in the docket.

In addition to HAP emissions reductions, this final rule will reduce other pollutants such as CO, NO_X, and VOC. This final rule is expected to reduce emissions of CO by 109,000 tpy in the year 2013. Reductions of NO_X are estimated at 96,000 tpy in the year 2013. Emissions of VOC are estimated to be reduced by 31,000 tpy in the year 2013.

B. What are the cost impacts?

The total national capital cost for this final rule for existing stationary RICE is estimated to be $383 million, with a total national annual cost of $253 million in year 2013 (the first year this final rule is implemented). Further information regarding the estimated cost impacts of this final rule can be found in the memorandum titled, "Impacts Associated with NESHAP for Existing Stationary SI RICE," which is available in the docket.

C. What are the benefits?

We estimate the monetized co-benefits of the final SI RICE NESHAP for major and area sources to be $510 million to $1.2 billion (2009$, 3 percent discount rate) in the implementation year (2013). The monetized co-benefits of the regulatory action at a 7 percent discount rate are $460 million to $1.1 billion (2009$). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower co-benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[1] A summary of the monetized co-benefits estimates at discount rates of 3 percent and 7 percent is presented in Table 3 of this preamble.

TABLE 3—SUMMARY OF THE MONETIZED CO-BENEFITS ESTIMATES FOR THE FINAL RICE SI NESHAP IN 2013

[Millions of 2009$] [1]

$PM_{2.5}$ precursors	Estimated emission reductions (tons per year)	Total monetized co-benefits (3% discount rate)	Total monetized co-benefits (7% discount rate)
Major Sources:			
VOC	6,730	$8.2 to $20	$7.4 to $18.
Area Sources:			
VOC	24,177	$29 to $72	$27 to $65.
NO_X	96,479	$470 to $1,100	$420 to $1,000.
Total for Area Sources		$500 to $1,200	$450 to $1,100.
Combined Total for Major and Area Sources		$510 to $1,200	$460 to $1,100.

[1] All estimates are for the implementation year (2013), and are rounded to two significant figures so numbers may not sum across rows. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form $PM_{2.5}$. Benefits from reducing CO and HAP are not included. All of the benefits for area sources are attributable to reductions expected from 4SLB and 4SRB non-emergency engines above 500 HP.

[1] Roman *et al.*, 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268–2274.

These co-benefits estimates represent the total monetized human health benefits for populations exposed to less $PM_{2.5}$ in 2013 from controls installed to reduce air pollutants in order to meet these multiple standards. These co-estimates are calculated as the sum of the monetized value of avoided premature mortality and morbidity associated with reducing a ton of $PM_{2.5}$ precursor emissions. To estimate the human health benefits derived from reducing $PM_{2.5}$ precursor emissions, we utilized the general approach and methodology laid out in Fann, Fulcher, and Hubbell (2009).[2]

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 ambient $PM_{2.5}$ levels and another model to estimate the changes in human health associated with that change in air quality. Finally, the monetized health co-benefits were divided by the emissions reductions to create the benefit-per-ton estimates. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. NO_X and VOCs are the primary $PM_{2.5}$ precursors affected by this rule. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form $PM_{2.5}$. 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 co-benefits would be lower.

For context, it is important to note that the magnitude of the PM co-benefits is largely driven by the concentration response function for premature mortality. Experts have advised EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. For this rulemaking we cite two key empirical studies, one based on the American Cancer Society cohort study[3] and the extended Six Cities cohort study.[4] In the RIA for this rulemaking, which is available in the docket, we also include co-benefits estimates derived from expert judgments and other assumptions.

EPA strives to use the best available science to support our benefits analyses. We recognize that interpretation of the science regarding air pollution and health is dynamic and evolving. After reviewing the scientific literature and recent scientific advice, we have determined that the no-threshold model is the most appropriate model for assessing the mortality benefits associated with reducing $PM_{2.5}$ exposure. Consistent with this recent advice, we are replacing the previous threshold sensitivity analysis with a new "Lowest Measured Level" (LML) assessment. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

Most of the estimated PM-related benefits in this rulemaking would accrue to populations exposed to higher levels of $PM_{2.5}$. Using the Pope *et al.* (2002) study, the 85 percent of the population is exposed at or above the LML of 7.5 $\mu g/m^3$. Using the Laden *et al.* (2006) study, 40 percent of the population is exposed above the LML of 10 $\mu g/m^3$. It is important to emphasize that we have high confidence in $PM_{2.5}$-related effects down to the lowest LML of the major cohort studies. This fact is important, because as we estimate PM-related mortality among populations exposed to levels of $PM_{2.5}$ that are successively lower, our confidence in the results diminishes. However, our analysis shows that the great majority of the impacts occur at higher exposures.

This analysis does not include the type of detailed uncertainty assessment found in the 2006 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA because we lack the necessary air quality input and monitoring data to run the benefits model. However, the 2006 $PM_{2.5}$ NAAQS benefits analysis[5] provides an indication of the sensitivity of our results to various assumptions.

It should be emphasized that the monetized co-benefits estimates provided above do not include benefits from several important benefit categories, including reducing other air pollutants, ecosystem effects, and visibility impairment. The benefits from reducing CO and HAP have not been monetized in this analysis, including reducing 109,000 tons of CO and 6,000 tons of HAP each year. Although we do not have sufficient information or modeling available to provide monetized estimates for this rulemaking, we include a qualitative assessment of these other effects in the RIA for this rulemaking, which is available in the docket.

The combined social costs of this rulemaking are estimated to be $253 million (2009$) in the implementation year. The combined monetized co-benefits are $510 million to $1.2 billion (2009$, 3 percent discount rate) and $460 million to $1.1 billion (2009$, 7 percent discount rate) for 2013. Thus, net benefits of this rulemaking are estimated at $250 million to $980 million (2009$, 3 percent discount rate) and $210 million to $860 million (2009$, 7 percent discount rate). EPA believes that the benefits of the rulemaking are likely to exceed the costs even when taking into account the uncertainties in the cost and benefit estimates.

D. What are the economic impacts?

The economic impact analysis (EIA) that is included in the RIA indicates that prices of affected output from the affected industries will increase as a result of the rule, but the changes will be small. The largest impacts are on the electric power generating industry because it bears more costs from the rule than any other affected industry (slightly more than 50 percent of the total annualized costs). For all affected industries, annualized compliance costs are 0.5 percent or less, on average, of sales for firms.

Based on the estimated compliance costs associated with this rule and the predicted changes in prices and output in affected markets, the estimated social costs are $253 million (2009$), which is the same as the estimated compliance costs.

For more information on the economic impacts, please refer to the RIA for this rulemaking, which is available in the docket.

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

[3] Pope *et al.*, 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." Journal of the American Medical Association 287:1132–1141.

[4] Laden *et al.*, 2006. "Reduction in Fine Particulate Air Pollution and Mortality." *American Journal of Respiratory and Critical Care Medicine.* 173: 667–672.

[5] U.S. Environmental Protection Agency, 2006. Final Regulatory Impact Analysis: $PM_{2.5}$ NAAQS. Prepared by Office of Air and Radiation. October. Available on the Internet at *http://www.epa.gov/ttn/ecas/ria.html.*

E. What are the non-air health, environmental and energy impacts?

EPA does not anticipate any significant non-air health, environmental or energy impacts as a result of this final rule.

VII. 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 a RIA of the potential costs and benefits associated with this action.

When estimating the $PM_{2.5}$-related human health benefits and compliance costs in Table 4 below, EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of this rulemaking. The RIA available in the docket describes in detail the empirical basis for EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below.

When characterizing uncertainty in the PM-mortality relationship, EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, EPA's 2009 Integrated Science Assessment for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship. In the RIA accompanying this rulemaking, rather than segmenting out impacts predicted to be associated levels above and below a "bright line" threshold, EPA includes a "LML" that illustrates the increasing uncertainty that characterizes exposure attributed to levels of $PM_{2.5}$ below the LML for each study. Figures provided in the RIA show the distribution of baseline exposure to $PM_{2.5}$, as well as the lowest air quality levels measured in each of the epidemiology cohort studies. This information provides a context for considering the likely portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction $PM_{2.5}$-related premature mortality diminishes as baseline concentrations of $PM_{2.5}$ are lowered. Using the Pope *et al.* (2002) study, the 85 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 7.5 $\mu g/m^3$. Using the Laden *et al.* (2006) study, 40 percent of the population is exposed above the LML of 10 $\mu g/m^3$. While the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

A summary of the monetized benefits, social costs, and net benefits for the option, as well as a less stringent option, at discount rates of 3 percent and 7 percent is in Table 4 of this preamble.

TABLE 4—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE FINAL SI RICE NESHAP IN 2013

[Millions of 2009$] [1]

	3% Discount rate			7% Discount rate		
Final NESHAP: Major						
Total Monetized Benefits [2]	$8.2	to	$20	$7.4	to	$18
Total Social Costs [3]	$88			$88		
Net Benefits	−$80	to	−$68	−$81	to	−$70
Non-monetized Benefits	12,500 tons of CO 1,300 tons of HAP Ecosystem effects Visibility impairment					
Alternative 2: Major						
Total Monetized Benefits [2]	$48	to	$120	$43	to	$110
Total Social Costs [3]	$95			$95		
Net Benefits	−$47	to	$22	−$52	to	$11
Non-monetized Benefits	17,800 tons of CO 1,400 tons of HAP Health effects from NO_2 and ozone exposure Ecosystem effects Visibility impairment					
Final NESHAP: Area [4]						
Total Monetized Benefits [2]	$500	to	$1,200	$450	to	$1,100
Total Social Costs [3]	$166			$166		

TABLE 4—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE FINAL SI RICE NESHAP IN 2013—Continued

[Millions of 2009$] [1]

	3% Discount rate			7% Discount rate		
Net Benefits	$330	to	$1,100	$290	to	$930
Non-monetized Benefits	97,000 tons of CO 4,700 tons of HAP Health effects from NO_2 and ozone exposure Ecosystem effects Visibility impairment					
Final Major and Area Source NESHAP						
Total Monetized Benefits [2]	$510	to	$1,200	$460	to	$1,100
Total Social Costs [3]	$253			$253		
Net Benefits	$250	to	$980	$210	to	$860
Non-monetized Benefits	109,000 tons of CO 6,000 tons of HAP Health effects from NO_2 and ozone exposure Ecosystem effects Visibility impairment					

[1] All estimates are for the implementation year (2013), and are rounded to two significant figures.
[2] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as NO_X and VOC. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Benefits are shown as a range from Pope *et al.* (2002) to Laden *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type.
[3] The annual compliance costs serve as a proxy for the annual social costs of this rulemaking given the lack of difference between the two.
[4] All of the benefits for area sources are attributable to reductions expected from 4SLB and 4SRB non-emergency engines above 500 HP.

For more information on the benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

The information collection requirements in this final rule 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 activities in this final rule include performance testing for non-emergency stationary SI RICE from 100 to 500 HP located at major sources of HAP and for non-emergency 4SLB and 4SRB stationary SI RICE larger than 500 HP located at area sources of HAP. The information collection activities also include one-time notifications and periodic reports, recording information, monitoring and the maintenance of records. The information generated by these activities will be used by EPA to ensure that affected facilities comply with the emission limits and other requirements. Records and reports are necessary to enable EPA or States to identify affected facilities that may not be in compliance with the requirements. Based on reported information, EPA will decide which units and what records or processes should be inspected. These amendments do not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B, Confidentiality of Business Information.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after sources must comply) is estimated to be 967,246 labor hours per year at a total annual cost of $86 million. This estimate includes notifications of compliance and performance tests, engine performance testing, semiannual compliance reports, continuous monitoring, and recordkeeping. The total capital costs associated with the requirements over the 3-year period of the information collection request (ICR) is estimated to be $13.8 million per year. There are no additional operation and maintenance costs for the requirements over the 3-year period of the ICR. 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 in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act

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

For purposes of assessing the impacts of this final rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental

jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. The companies owning facilities with affected RICE can be grouped into small and large categories using SBA general size standard definitions. Size standards are based on industry classification codes (*i.e.*, North American Industrial Classification System, or NAICS) that each company uses to identify the industry or industries in which they operate in. The SBA defines a small business in terms of the maximum employment, annual sales, or annual energy-generating capacity (for electricity generating units) of the owning entity. These thresholds vary by industry and are evaluated based on the primary industry classification of the affected companies. In cases where companies are classified by multiple NAICS codes, the most conservative SBA definition (*i.e.*, the NAICS code with the highest employee or revenue size standard) was used.

As mentioned earlier in this preamble, facilities across several industries use affected SI RICE; therefore, a number of size standards are utilized in this analysis. For the 15 industries identified at the 6-digit NAICS codes represented in this analysis, the employment size standard (where it applies) varies from 500 to 1,000 employees. The annual sales standard (where it applies) is as low as $0.75 million and as high as $33.5 million. In addition, for the electric power generation industry, the small business size standard is an ultimate parent entity defined as having a total electric output of 4 million megawatt-hours in the previous fiscal year. The specific SBA size standard is identified for each affected industry within the industry profile to support this economic analysis.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities (SISNOSE). This certification is based on the economic impact of this final action to all affected small entities across all industries affected. We estimate that all small entities will have annualized costs of less than 1 percent of their sales in all industries except NAICS 2211 (electric power generation, transmission, and distribution) and NAICS 111 (Crop and Animal Production). The number of small entities in NAICS 2211 having annualized costs of greater than 1 percent of their sales is less than 5 percent, and the number of small entities in NAICS 111 and 112 having annualized costs of greater than 1 percent of their sales (but less than 2 percent of sales) is 30 percent. We conclude that there is no SISNOSE for this final rule.

For more information on the small entity impacts associated with this final rule, please refer to the Economic Impact and Small Business Analyses in the public docket. These analyses can be found in the RIA for this final rule.

Although this final rule would not have a significant economic impact on a substantial number of small entities, EPA nonetheless tried to reduce the impact of this final rule on small entities. When developing the standards, EPA took special steps to ensure that the burdens imposed on small entities were minimal. EPA conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. In this final rule, we are applying the minimum level of control (*i.e.*, the MACT floor) to engines located at major HAP sources and the minimum level of testing, monitoring, recordkeeping, and reporting to affected RICE sources, both major and area, allowed by the CAA. Other alternatives considered that provided more than the minimum level of control were deemed as not technically feasible or cost-effective for EPA to implement as explained earlier in the preamble.

D. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. This final rule contains 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. Accordingly, EPA has prepared under section 202 of the UMRA a written statement which is summarized below.

As discussed previously in this preamble, the statutory authority for this final rule is section 112 of the CAA. Section 112(b) lists the 189 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP. Section 112(d) of the CAA directs us to develop NESHAP based on MACT, which require existing and new major sources to control emissions of HAP. EPA is required to address HAP emissions from stationary RICE located at area sources under section 112(k) of the CAA, based on criteria set forth by EPA in the Urban Air Toxics Strategy previously discussed in this preamble.

In compliance with section 205(a), we identified and considered a reasonable number of regulatory alternatives. EPA carefully examined the regulatory alternatives, and selected the lowest cost/least burdensome alternative that EPA deems adequate to achieve the statutory requirements of CAA section 112 and effectively reduce emissions of HAP.

1. Social Costs and Benefits

The RIA prepared for this final rule, including the Agency's assessment of costs and benefits, is detailed in the "Regulatory Impact Analysis for the Final SI RICE NESHAP" in the docket. Based on estimated compliance costs on all sources associated with this final rule and the predicted change in prices and production in the affected industries assuming passthrough of costs to affected consumers, the estimated social costs of this final rule are $253 million (2009$). It is estimated that by 2013, HAP will be reduced by 6,000 tpy due to reductions in formaldehyde, acetaldehyde, acrolein, methanol and benzene from existing stationary SI RICE. Formaldehyde and acetaldehyde have been classified as "probable human carcinogens." Acrolein and methanol are not considered carcinogenic, but produce several other toxic effects. Benzene is classified as a known carcinogen (Group A). This final rule is expected to reduce emissions of CO by about 109,000 tpy in the year 2013. Reductions of NO_X are estimated at 96,000 tpy in the year 2013. Emissions of VOC are estimated to be reduced by 31,000 tpy in the year 2013. Exposure to CO can affect the cardiovascular system and the central nervous system.

The total monetized benefits of this final rule in 2013 range from $510 million to $1.2 billion (2009$, 3% discount rate).

2. Future and Disproportionate Costs

The UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by this final rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of this final rule are discussed previously in this preamble. We do not believe that there will be any

disproportionate budgetary effects of this final rule on any particular areas of the country, State or local governments, types of communities (*e.g.*, urban, rural), or particular industry segments.

3. Effects on the National Economy

The UMRA requires that we estimate the effect of this final rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material. The nationwide economic impact of this final rule is presented in the "Regulatory Impact Analysis for the SI RICE NESHAP" in the docket. This analysis provides estimates of the effect of this final rule on most of the categories mentioned above. The results of the economic impact analysis were summarized previously in this preamble. In addition, we have determined that this final rule contains no regulatory requirements that might significantly or uniquely affect small governments. Therefore, this rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

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. This final rule primarily affects private industry, and does not impose significant economic costs on State or local governments. Thus, Executive Order 13132 does not apply to this final rule.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this final rule.

G. Executive Order 13045: Protection of Children From Environmental Health 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 Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is based solely on technology performance.

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

This final rule is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse impact on the supply, distribution, or use of energy. EPA has prepared an analysis of energy impacts that explains this conclusion as follows below.

With respect to energy supply and prices, our analysis suggests that at the industry level, the annualized costs represent a very small fraction of revenue (generally less than 0.5 percent). As a result, we can conclude supply and price impacts on affected energy producers and consumers should be small.

To enhance understanding regarding the regulation's influence on energy consumption, we examined publicly available data describing energy consumption for the electric power sector. The electric power sector is expected to incur about half of the $253 million in compliance costs associated with this final rule, and is the industry expected to incur the greatest share of the costs relative to other affected industries. The Annual Energy Outlook 2010 (EIA, 2009) provides energy consumption data. Since this final rule primarily affects natural gas and gasoline-fired RICE, our analysis focuses on impacts of consumption of these fuels. As shown in Table 5 of this preamble, the electric power sector accounts for less than 5.1 percent of U.S. natural gas consumption. As a result, any energy consumption changes attributable to this final rule should not significantly influence the supply, distribution, or use of energy nationwide.

TABLE 5—U.S. ELECTRIC POWER[a] SECTOR ENERGY CONSUMPTION

[(Quadrillion BTUs): 2013]

	Quantity	Share of total energy use (percent)
Distillate fuel oil	0.12	0.1
Residual fuel oil	0.34	0.3
Liquid fuels subtotal	0.45	0.5
Natural gas	5.17	5.1
Steam coal	20.69	20.6
Nuclear power	8.59	8.5
Renewable energy[b]	6.06	6.0
Electricity Imports	0.09	0.1
Total Electric Power Energy Consumption[c]	41.18	40.9
Delivered Energy Use	72.41	72.0
Total Energy Use	100.59	100.0

[a] Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[b] Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.

[c] Includes non-biogenic municipal waste not included above.

Source: U.S. Energy Information Administration. 2009. Supplemental Tables to the Annual Energy Outlook 2010.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113, Section 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. The 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 does not use available and applicable VCS.

EPA cites technical standard EPA Method 323 of 40 CFR part 63, appendix A, in this final rule. Consistent with the NTTAA, EPA conducted searches to identify VCS in addition to this EPA method. No applicable VCS were identified for EPA Method 323. The search and review results have been documented and are placed in the docket for this final rule.

Under § 63.7(f) and § 63.8(f) of subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required or referenced testing methods, performance specifications, or procedures.

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 increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This rule is a nationwide standard that reduces air toxics emissions from existing stationary SI engines, thus decreasing the amount of such emissions to which all affected populations are exposed.

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 final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of this final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2). This final rule will be effective on October 19, 2010.

List of Subjects in 40 CFR Part 63

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

Dated: August 10, 2010.

Lisa P. Jackson,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

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

Subpart ZZZZ—[Amended]

■ 2. Section 63.6590 is amended by revising paragraphs (b)(2), (b)(3), and (c) to read as follows:

§ 63.6590 What parts of my plant does this subpart cover?

* * * * *

(b) * * *

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(vi) Existing residential emergency stationary RICE located at an area source of HAP emissions;

(vii) Existing commercial emergency stationary RICE located at an area source of HAP emissions; or

(viii) Existing institutional emergency stationary RICE located at an area source of HAP emissions.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less

than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

■ 3. Section 63.6595 is amended by revising paragraph (a)(1) to read as follows:

§ 63.6595 When do I have to comply with this subpart?

(a) * * *

(1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than October 19, 2013.

* * * * *

■ 4. Section 63.6601 is amended by revising the section heading to read as follows:

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

* * * * *

■ 5. Section 63.6602 is revised to read as follows:

§ 63.6602 What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

■ 6. Section 63.6603 is amended by revising the section heading and paragraph (a) to read as follows:

§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

* * * * *

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

* * * * *

■ 7. Section 63.6604 is revised to read as follows:

§ 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. Existing non-emergency CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, or at area sources in areas of Alaska not accessible by the FAHS are exempt from the requirements of this section.

■ 8. Section 63.6611 is amended by revising the section heading to read as follows:

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

* * * * *

■ 9. Section 63.6612 is amended by revising the introductory text to read as follows:

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

* * * * *

■ 10. Section 63.6625 is amended by:
■ a. Revising paragraph (b);
■ b. Revising paragraph (e);
■ c. Revising paragraph (g) introductory text;
■ d. Revising paragraph (h);
■ e. Revising paragraph (i); and
■ f. Adding paragraphs (j) and (k) to read as follows:

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

* * * * *

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (8) of this section.

(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to

provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any 15-minute period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (b)(3) of this section.

(5) Record the results of each inspection, calibration, and validation check.

(6) You must develop a site-specific monitoring plan that addresses paragraphs (b)(6)(i) through (vi) of this section.

(i) Installation of the CPMS sampling probe or other interface at the appropriate location to obtain representative measurements;

(ii) Performance and equipment specifications for the sample interface, parametric signal analyzer, and the data collection and reduction systems;

(iii) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations);

(iv) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (c)(3), and (c)(4)(ii);

(v) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(vi) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i).

(7) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(8) You must operate and maintain the CPMS in continuous operation according to the site-specific monitoring plan.

* * * * *

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start landfill or digester gas stationary RICE located at an area source of HAP emissions;

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

* * * * *

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (g)(2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska not accessible by the FAHS do not have to meet the requirements of paragraph (g) of this section.

* * * * *

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table

2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(k) If you have an operating limitation that requires the use of a temperature measurement device, you must meet the requirements in paragraphs (k)(1) through (4) of this section.

(1) Locate the temperature sensor and other necessary equipment in a position that provides a representative temperature.

(2) Use a temperature sensor with a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit), or 1.0 percent of the temperature value, whichever is larger, for a noncryogenic temperature range.

(3) Use a temperature sensor with a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit), or 2.5 percent of the temperature value, whichever is larger, for a cryogenic temperature range.

(4) Conduct a temperature measurement device calibration check at least every 3 months.

■ 11. Section 63.6640 is amended by revising paragraph (f) to read as follows:

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

* * * * *

(f) *Requirements for emergency stationary RICE.* (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed on or after June 12, 2006, or an existing emergency stationary RICE located at an area source of HAP emissions, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year.

(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power.

(2) If you own or operate an emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed prior to June 12, 2006, you must operate the engine according to the conditions described in paragraphs (f)(2)(i) through (iii) of this section. If you do not operate the engine according to the requirements in paragraphs (f)(2)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.

(iii) You may operate your emergency stationary RICE for an additional 50 hours per year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

■ 12. Section 63.6645 is amended by revising paragraphs (a)(1), (a)(2), and (a)(5) to read as follows:

§ 63.6645 What notifications must I submit and when?

(a) * * *

(1) An existing stationary RICE with a site rating of less than or equal to 500

brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

* * * * *

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

* * * * *

■ 13. Section 63.6655 is amended by revising paragraphs (e)(1) through (e)(3) and (f)(1) and (f)(2) to read as follows:

§ 63.6655 What records must I keep?

* * * * *

(e) * * *

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) * * *

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

■ 14. Section 63.6675 is amended by:

■ a. Adding in alphabetical order the definition of *Commercial emergency stationary RICE;*

■ b. Revising the definition of *Emergency stationary RICE;*

■ c. Adding in alphabetical order the definition of *Institutional emergency stationary RICE;*

■ d. Adding in alphabetical order the definition of *Residential emergency stationary RICE;* and

■ e. Removing the definition of *Residential/commercial/institutional emergency stationary RICE* to read as follows:

§ 63.6675 What definitions apply to this subpart?

* * * * *

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

* * * * *

Emergency stationary RICE means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, *etc.* Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary RICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted under § 63.6640(f). All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

* * * * *

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

* * * * *

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

* * * * *

■ 15. Table 1a to Subpart ZZZZ of Part 63 heading and introductory text is revised to read as follows:

Table 1a to Subpart ZZZZ of Part 63. Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE > 500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

* * * * *

■ 16. Table 1b to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 1b to Subpart ZZZZ of Part 63. Operating Limitations for Existing, New, and Reconstructed Spark Ignition 4SRB Stationary RICE > 500 HP Located at a Major Source of HAP Emissions and Existing Spark Ignition 4SRB Stationary RICE > 500 HP Located at an Area Source of HAP Emissions

As stated in §§ 63.6600, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE > 500 HP located at a major source of HAP emissions and existing 4SRB stationary RICE > 500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O_2 and using NSCR.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus; 10 percent from the pressure drop across the catalyst measured during the initial performance test and b. maintain the termperature of your stationary RICE exhaust so the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.

For each . . .	You must meet the following operating limitation . . .
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O_2 and using NSCR.	Comply with any operating limitations approved by the Administrator.

■ 17. Table 2b to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 2b to Subpart ZZZZ of Part 63. Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE > 500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥ 250 HP Located at a Major Source of HAP Emissions, Existing Compression Ignition Stationary RICE > 500 HP, and Existing 4SLB Stationary RICE > 500 HP Located at an Area Source of HAP Emissions

As stated in §§ 63.6600, 63.6601, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and compression ignition stationary RICE located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥ 250 HP located at a major source of HAP emissions; existing compression ignition stationary RICE > 500 HP; and existing 4SLB stationary RICE > 500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	Comply with any operating limitations approved by the Administrator.

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(g) for a different temperature range.

■ 18. Table 2c to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 2c to Subpart ZZZZ of Part 63. Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤ 500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤ 500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
2. Non-Emergency, non-black start stationary CI RICE < 100 HP.	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first; [2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100 ≤ HP ≤ 300 HP.	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	
4. Non-Emergency, non-black start CI stationary RICE 300 < HP ≤ 500.	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP.	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; [2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE < 100 HP that are not 2SLB stationary RICE.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; [2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE < 100 HP.	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first; [2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100 ≤ HP ≤ 500.	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100 ≤ HP ≤ 500.	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	
11. Non-emergency, non-black start 4SRB stationary RICE 100 ≤ HP ≤ 500.	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start landfill or digester gas-fired stationary RICE 100 ≤ HP ≤ 500.	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

■ 19. Table 2d to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 2d to Subpart ZZZZ of Part 63. Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP.	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first; [1]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500.	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP.	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; [1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; [1]	
	b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE.	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first; [1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; [1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB stationary RICE >500 HP.	a. Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 93 percent or more.	
9. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; [1]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
10. Non-emergency, non-black start 4SRB stationary RICE >500 HP.	a. Limit concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd at 15 percent O_2; or b. Reduce formaldehyde emissions by 76 percent or more.	
11. Non-emergency, non-black start landfill or digester gas-fired stationary RICE.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; [1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

■ 20. Table 3 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 3 to Subpart ZZZZ of Part 63. Subsequent Performance Tests

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE with a brake horsepower >500 located at major sources; new or reconstructed 4SLB stationary RICE with a brake horsepower ≥250 located at major sources; and new or reconstructed CI stationary RICE with a brake horsepower >500 located at major sources.	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semi-annually.[1]
2. 4SRB stationary RICE with a brake horsepower ≥5,000 located at major sources.	Reduce formaldehyde emissions	Conduct subsequent performance tests semi-annually.[1]
3. Stationary RICE with a brake horsepower >500 located at major sources and new or reconstructed 4SLB stationary RICE with a brake horsepower 250≤HP≤500 located at major sources.	Limit the concentration of formaldehyde in the stationary RICE exhaust.	Conduct subsequent performance tests semi-annually.[1]
4. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are not limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year that are not limited use stationary RICE.	Limit or reduce CO or formaldehyde emissions.	Conduct subsequent performance tests every 8,760 hrs. or 3 years, whichever comes first.

For each . . .	Complying with the requirement to . . .	You must . . .
5. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year and are limited use stationary RICE.	Limit or reduce CO or formaldehyde emissions.	Conduct subsequent performance tests every 8,760 hrs. or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

■ 21. Table 4 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE.	a. Reduce CO emissions ..	i. Measure the O_2 at the inlet and outlet of the control device; and	(1) Portable CO and O_2 analyzer.	(a) Using ASTM D6522–00 (2005) [a] (incorporated by reference, see § 63.14). Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device.	(1) Portable CO and O_2 analyzer.	(a) Using ASTM D6522–00 (2005) [a b] (incorporated by reference, see § 63.14) or Method 10 of 40 CFR appendix A. The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE ..	a. Reduce formaldehyde emissions.	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00m (2005).	(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device.	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	(a) If using a control device, the sampling site must be located at the outlet of the control device.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005).	(a) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE.	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005),[a] Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.	(a) CO Concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour longer runs.

[a] You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106. ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

[b] You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.

[c] You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

■ 22. Table 5 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 5 to Subpart ZZZZ of Part 63. Initial Compliance With Emission Limitations and Operating Limitations

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE > 500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce CO emissions and not using oxidation catalyst.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce formaldehyde emissions and using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce formaldehyde emissions and not using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
6. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
8. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP.	a. Reduce CO or formaldehyde emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
9. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP.	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.

■ 23. Table 6 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 6 to Subpart ZZZZ of Part 63. Continuous Compliance With Emission Limitations, Operating Limitations, Work Practices, and Management Practices

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP.	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved; [a] and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP.	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved; [a] and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP, existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year.	a. Reduce CO emissions and using a CEMS	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and using NSCR.	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and not using NSCR.	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP.	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a] and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a] and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year.	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE.	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using oxidation catalyst or NSCR.	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE.	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using oxidation catalyst or NSCR.	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year.	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR.	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year.	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR.	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

■ 24. Table 7 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 7 to Subpart ZZZZ of Part 63. Requirements for Reports

As stated in § 63.6650, you must comply with the following requirements for reports:

For each ...	You must submit a ...	The report must contain ...	You must submit the report ...
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE > 500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP and operated more than 24 hours per calendar year; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP.	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4)	i. Semiannually according to the requirements in §63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations. i. Semiannually according to the requirements in §63.6650(b). i. Semiannually according to the requirements in §63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in §63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.

■ 25. Appendix A to Part 63 is amended by adding, in numerical order, Method 323 to read as follows:

Appendix A to Part 63—Test Methods

* * * * *

Method 323—Measurement of Formaldehyde Emissions From Natural Gas-Fired Stationary Sources—Acetyl Acetone Derivitization Method

1.0 Introduction. This method describes the sampling and analysis procedures of the acetyl acetone colorimetric method for measuring formaldehyde emissions in the exhaust of natural gas-fired, stationary combustion sources. This method, which was prepared by the Gas Research Institute (GRI), is based on the Chilled Impinger Train Method for Methanol, Acetone, Acetaldehyde, Methyl Ethyl Ketone, and Formaldehyde (Technical Bulletin No. 684) developed and published by the National Council of the Paper Industry for Air and Stream Improvement, Inc. (NCASI). However, this method has been prepared specifically for formaldehyde and does not include specifications (*e.g.*, equipment and supplies) and procedures (*e.g.*, sampling and analytical) for methanol, acetone, acetaldehyde, and methyl ethyl ketone. To obtain reliable results, persons using this method should have a thorough knowledge of at least Methods 1 and 2 of 40 CFR Part 60, Appendix A–1; Method 3 of 40 CFR Part 60, Appendix A–2; and Method 4 of 40 CFR Part 60, Appendix A–3.

1.1 Scope and Application

1.1.1 Analytes. The only analyte measured by this method is formaldehyde (CAS Number 50–00–0).

1.1.2 Applicability. This method is for analyzing formaldehyde emissions from uncontrolled and controlled natural gas-fired, stationary combustion sources.

1.1.3 Data Quality Objectives. If you adhere to the quality control and quality assurance requirements of this method, then you and future users of your data will be able to assess the quality of the data you obtain and estimate the uncertainty in the measurements.

2.0 Summary of Method. An emission sample from the combustion exhaust is drawn through a midget impinger train containing chilled reagent water to absorb formaldehyde. The formaldehyde concentration in the impinger is determined by reaction with acetyl acetone to form a colored derivative which is measured colorimetrically.

3.0 Definitions

[Reserved].

4.0 Interferences. The presence of acetaldehyde, amines, polymers of formaldehyde, periodate, and sulfites can cause interferences with the acetyl acetone procedure which is used to determine the formaldehyde concentration. However, based on experience gained from extensive testing of natural gas-fired combustion sources using FTIR to measure a variety of compounds, GRI expects only acetaldehyde to be potentially present when combusting natural gas. Acetaldehyde has been reported to be a significant interference only when present at concentrations above 50 ppmv. However, GRI reports that the concentration of acetaldehyde from gas-fired sources is very low (typically below the FTIR detection limit of around 0.5 ppmv); therefore, the potential positive bias due to acetaldehyde interference is expected to be negligible.

5.0 Safety

5.1 Prior to applying the method in the field, a site-specific Health and Safety Plan should be prepared. General safety precautions include the use of steel-toed boots, safety glasses, hard hats, and work gloves. In certain cases, facility policy may require the use of fire-resistant clothing while on-site. Since the method involves testing at high-temperature sampling locations, precautions must be taken to limit the potential for exposure to high-temperature gases and surfaces while inserting or removing the sample probe. In warm locations, precautions must also be taken to avoid dehydration.

5.2 Potential chemical hazards associated with sampling include formaldehyde, nitrogen oxides (NO_X), and carbon monoxide (CO). Formalin solution, used for field spiking, is an aqueous solution containing formaldehyde and methanol. Formaldehyde is a skin, eye, and respiratory irritant and a carcinogen, and should be handled accordingly. Eye and skin contact and inhalation of formaldehyde vapors should be avoided. Natural gas-fired combustion sources can potentially emit CO at toxic concentrations. Care should be taken to minimize exposure to the sample gas while inserting or removing the sample probe. If the work area is enclosed, personal CO monitors should be used to insure that the concentration of CO in the work area is maintained at safe levels.

5.3 Potential chemical hazards associated with the analytical procedures include acetyl acetone and glacial acetic acid. Acetyl acetone is an irritant to the skin and respiratory system, as well as being moderately toxic. Glacial acetic acid is highly corrosive and is an irritant to the skin, eyes, and respiratory system. Eye and skin contact and inhalation of vapors should be avoided. Acetyl acetone and glacial acetic acid have flash points of 41 °C (105.8 °F) and 43 °C (109.4 °F), respectively. Exposure to heat or flame should be avoided.

6.0 Equipment and Supplies

6.1 Sampling Probe. Quartz glass probe with stainless steel sheath or stainless steel probe.

6.2 Teflon Tubing. Teflon tubing to connect the sample probe to the impinger train. A heated sample line is not needed since the sample transfer system is rinsed to recover condensed formaldehyde and the rinsate combined with the impinger contents prior to sample analysis.

6.3 Midget Impingers. Three midget impingers are required for sample collection. The first impinger serves as a moisture knockout, the second impinger contains 20 mL of reagent water, and the third impinger contains silica gel to remove residual moisture from the sample prior to the dry gas meter.

6.4 Vacuum Pump. Vacuum pump capable of delivering a controlled extraction flow rate between 0.2 and 0.4 L/min.

6.5 Flow Measurement Device. A rotameter or other flow measurement device is required to indicate consistent sample flow.

6.6 Dry Gas Meter. A dry gas meter is used to measure the total sample volume collected. The dry gas meter must be sufficiently accurate to measure the sample volume to within 2 percent, calibrated at the selected flow rate and conditions actually encountered during sampling, and equipped with a temperature sensor (dial thermometer, or equivalent) capable of measuring temperature accurately to within 3 °C (5.4 °F).

6.7 Spectrophotometer. A spectrophotometer is required for formaldehyde analysis, and must be capable of measuring absorbance at 412 nm.

7.0 Reagents and Standards

7.1 Sampling Reagents

7.1.1 Reagent water. Deionized, distilled, organic-free water. This water is used as the capture solution, for rinsing the sample probe, sample line, and impingers at the completion of the sampling run, in reagent dilutions, and in blanks.

7.1.2 Ice. Ice is necessary to pack around the impingers during sampling in order to keep the impingers cold. Ice is also needed for sample transport and storage.

7.2 Analysis

7.2.1 Acetyl acetone Reagent. Prepare the acetyl acetone reagent by dissolving 15.4 g of ammonium acetate in 50 mL of reagent water in a 100-mL volumetric flask. To this solution, add 0.20 mL of acetyl acetone and 0.30 mL of glacial acetic acid. Mix the solution thoroughly, then dilute to 100 mL with reagent water. The solution can be stored in a brown glass bottle in the refrigerator, and is stable for at least two weeks.

7.2.2 Formaldehyde. Reagent grade.

7.2.3 Ammonium Acetate

7.2.4 Glacial Acetic Acid

8.0 Sample Collection, Preservation, Storage, and Transport

8.1 Pre-test

8.1.1 Collect information about the site characteristics such as exhaust pipe diameter, gas flow rates, port location, access to ports, and safety requirements during a pre-test site survey. You should then decide the sample collection period per run and the target sample flow rate based on your best estimate of the formaldehyde concentration likely to be present. You want to assure that sufficient formaldehyde is captured in the impinger solution so that it can be measured precisely by the spectrophotometer. You may use Equation 323–1 to design your test program. As a guideline for optimum performance, if you can, design your test so that the liquid concentration (C_l) is approximately 10 times the assumed spectrophotometer detection limit of 0.2 µg/mL. However, since actual detection limits are instrument specific, we also suggest that you confirm that the laboratory equipment can meet or exceed this detection limit.

8.1.2 Prepare and then weigh the midget impingers prior to configuring the sampling train. The first impinger is initially dry. The second impinger contains 20 mL of reagent water, and the third impinger contains silica gel that is added before weighing the impinger. Each prepared impinger is weighed and the pre-sampling weight is recorded to the nearest 0.5 gm.

8.1.3 Assemble the sampling train (see Figure 1). Ice is packed around the impingers in order to keep them cold during sample collection. A small amount of water may be added to the ice to improve thermal transfer.

8.1.4 Perform a sampling system leak check (from the probe tip to the pump outlet) as follows: Connect a rotameter to the outlet of the pump. Close off the inlet to the probe and observe the leak rate. The leak rate must be less than 2 percent of the planned sampling rate of 0.2 or 0.4 L/min.

8.1.5 Source gas temperature and static pressure should also be considered prior to field sampling to ensure adequate safety precautions during sampling.

8.2 Sample Collection

8.2.1 Set the sample flow rate between 0.2–0.4 L/min, depending upon the anticipated concentration of formaldehyde in the engine exhaust. (You may have to refer to published data for anticipated concentration levels—see References 5 and 6.) If no information is available for the anticipated levels of formaldehyde, use the higher sampling rate of 0.4 L/min.

8.2.2 Record the sampling flow rate every 5 to 10 minutes during the sample collection period. **NOTE:** It is critical that you do not sample at a flow rate higher than 0.4 L/min. Sampling at higher flow rates may reduce formaldehyde collection efficiency resulting in measured formaldehyde concentrations that are less than the actual concentrations.

8.2.3 Monitor the amount of ice surrounding the impingers and add ice as necessary to maintain the proper impinger temperature. Remove excess water as needed to maintain an adequate amount of ice.

8.2.4 Record measured leak rate, beginning and ending times and dry gas meter readings for each sampling run, impinger weights before and after sampling, and sampling flow rates and dry gas meter exhaust temperature every 5 to 10 minutes during the run, in a signed and dated notebook.

8.2.5 If possible, monitor and record the fuel flow rate to the engine and the exhaust oxygen concentration during the sampling period. This data can be used to estimate the engine exhaust flow rate based on the Method 19 approach. This approach, if accurate fuel flow rates can be determined, is preferred for reciprocating IC engine exhaust flow rate estimation due to the pulsating nature of the engine exhaust. The F–Factor procedures described in Method 19 may be used based on measurement of fuel flow rate and exhaust oxygen concentration. One example equation is Equation 323–2.

8.3 Post-test. Perform a sampling system leak-check (from the probe tip to pump outlet). Connect a rotameter to the outlet of the pump. Close off the inlet to the probe and observe the leak rate. The leak rate must be less than 2 percent of the sampling rate. Weigh and record each impinger immediately after sampling to determine the moisture weight gain. The impinger weights are measured before transferring the impinger contents, and before rinsing the sample probe and sample line. The moisture content of the exhaust gas is determined by measuring the weight gain of the impinger solutions and volume of gas sampled as described in Method 4. Rinse the sample probe and sample line with reagent water. Transfer the impinger catch to an amber 40-mL VOA bottle with a Teflon-lined cap. If there is a small amount of liquid in the dropout impinger (< 10 mL), the impinger catches can be combined in one 40 mL VOA bottle. If there is a larger amount of liquid in the dropout impinger, use a larger VOA bottle to combine the impinger catches. Rinse the impingers and combine the rinsings from the sample probe, sample line, and impingers with the impinger catch. In general, combined rinse volumes should not exceed 10 mL. However, in cases where a long, flexible extension line must be used to connect the sample probe to the sample box, sufficient water must be used to rinse the connecting line to insure that any sample that may have collected there is recovered. The volume of the rinses during sample recovery should not be excessive as this may result in your having to use a larger VOA bottle. This in turn would raise the detection limit of the method since after combining the rinses with the impinger catches in the VOA bottle, the bottle should be filled with reagent water to eliminate the headspace in the sample vial. Keep the sample bottles over ice until analyzed on-site or received at the laboratory. Samples should be analyzed as soon as possible to minimize possible sample degradation. Based on a limited number of previous analyses, samples held in refrigerated conditions showed some sample degradation over time.

8.4 Quality Control Samples

8.4.1 Field Duplicates. During at least one run, a pair of samples should be collected concurrently and analyzed as separate samples. Results of the field duplicate samples should be identified and reported with the sample results. The percent difference in exhaust (stack) concentration indicated by field duplicates should be within 20 percent of their mean concentration. Data are to be flagged as suspect if the duplicates do not meet the acceptance criteria.

8.4.2 Spiked Samples. An aliquot of one sample from each source sample set should be spiked at 2 to 3 times the formaldehyde level found in the unspiked sample. It is also recommended that a second aliquot of the same sample be spiked at around half the level of the first spike; however, the second spike is not mandatory. The results are acceptable if the measured spike recovery is 80 to 120 percent. Use Equation 323–4. Data are to be flagged as suspect if the spike recovery do not meet the acceptance criteria.

8.4.3 Field Blank. A field blank consisting of reagent water placed in a clean impinger train, taken to the test site but not sampled, then recovered and analyzed in the same manner as the other samples, should be collected with each set of source samples. The field blank results should be less than 50 percent of the lowest calibration standard used in the sample analysis. If this criteria is not met, the data should be flagged as suspect.

9.0 Quality Control

QA/QC	Acceptance	Frequency	Corrective action
Leak-check—Sections 8.1.4, 8.3 ...	<2% of Sampling rate	Pre- and Post-sampling	Pre-sampling: Repair leak and re-check Post-sampling: Flag data and repeat run if for regulatory compliance.
Sample flow rate	Between 0.2 and 0.4 L/min	Throughout sampling	Adjust.
VOA vial headspace	No headspace	After sample recovery	Flag data.
Sample preservation	Maintain on ice	After sample recovery	Flag data.
Sample hold time	14 day maximum	After sample recovery	Flag data.
Field Duplicates—Section 8.4.1	Within 20% of mean of original and duplicate sample.	One duplicate per source sample set.	Flag data.
Spiked Sample—Section 8.4.2	Recovery between 80 and 120%	One spike per source sample set	Flag data.
Field Blank—Section 8.4.3	<50% of the lowest calibration standard.	One blank per source sample set	Flag data.
Calibration Linearity—Section 10.1	Correlation coefficient of 0.99 or higher.	Per source sample set	Repeat calibration procedures.
Calibration Check Standard—Section 10.3.	Within 10% of theoretical value	One calibration check per source sample set.	Repeat check, remake standard and repeat, repeat calibration.
Lab Duplicates—Section 11.2.1	Within 10% of mean of original and duplicate sample analysis.	One duplicate per 10 samples	Flag data.
Analytical Blanks—Section 11.2.2	<50% of the lowest calibration standard.	One blank per source sample set	Clean glassware/analytical equipment and repeat.

10.0 Calibration and Standardization

10.1 Spectrophotometer Calibration. Prepare a stock solution of 10 µg/mL formaldehyde. Prepare a series of calibration standards from the stock solution by adding 0, 0.1, 0.3, 0.7, 1.0, and 1.5 mL of stock solution (corresponding to 0, 1.0, 3.0, 7.0, 10.0, and 15.0 µg formaldehyde, respectively) to screw-capped vials. Adjust each vial's volume to 2.0 mL with reagent water. At this point the concentration of formaldehyde in the standards is 0.0, 0.5, 1.5, 3.5, 5.0, and 7.5 µg/mL, respectively. Add 2.0 mL of acetyl acetone reagent, thoroughly mix the solution, and place the vials in a water bath (or heating block) at 60 °C for 10 minutes. Remove the vials and allow to cool to room temperature. Transfer each solution to a cuvette and measure the absorbance at 412 nm using the spectrophotometer. Develop a calibration curve from the analytical results of these standards. The acceptance criteria for the spectrophotometer calibration is a correlation coefficient of 0.99 or higher. If this criteria is not met, the calibration procedures should be repeated.

10.2 Spectrophotometer Zero. The spectrophotometer should be zeroed with reagent water when analyzing each set of samples.

10.3 Calibration Checks. Calibration checks consisting of analyzing a standard separate from the calibration standards must be performed with each set of samples. The calibration check standard should not be prepared from the calibration stock solution. The result of the check standard must be within 10 percent of the theoretical value to be acceptable. If the acceptance criteria are not met, the standard must be reanalyzed. If still unacceptable, a new calibration curve must be prepared using freshly prepared standards.

11.0 Analytical Procedure

11.1 Sample Analysis. A 2.0-mL aliquot of the impinger catch/rinsate is transferred to a screw-capped vial. Two mL of the acetyl acetone reagent are added and the solution is thoroughly mixed. Once mixed, the vial is placed in a water bath (or heating block) at 60 °C for 10 minutes. Remove the vial and allow to cool to room temperature. Transfer the solution to a cuvette and measure the absorbance using the spectrophotometer at 412 nm. The quantity of formaldehyde present is determined by comparing the sample response to the calibration curve. Use Equation 323–5. If the sample response is out of the calibration range, the sample must be diluted and reanalyzed. Such dilutions must be performed on another aliquot of the original sample before the addition of the acetyl acetone reagent. The full procedure is repeated with the diluted sample.

11.2 Analytical Quality Control

11.2.1 Laboratory Duplicates. Two aliquots of one sample from each source sample set should be prepared and analyzed (with a minimum of one pair of aliquots for every 10 samples). The percent difference between aliquot analysis should be within 10 percent of their mean. Use Equation 323–3. Data are flagged if the laboratory duplicates do not meet this criteria.

11.2.2 Analytical blanks. Blank samples (reagent water) should be incorporated into each sample set to evaluate the possible presence of any cross-contamination. The acceptance criteria for the analytical blank is less than 50 percent of the lowest calibration standard. If the analytical blank does not meet this criteria, the glassware/analytical equipment should be cleaned and the analytical blank repeated.

12.0 Calculations and Data Analysis

12.1 Nomenclature

A = measured absorbance of 2 mL aliquot
B = estimated sampling rate, Lpm
C_l = target concentration in liquid, µg/mL
D = estimated stack formaldehyde concentration (ppmv)
E = estimated liquid volume, normally 40 mL (the size of the VOA used)
c_{form} = formaldehyde concentration in gas stream, ppmvd
c_{form} @15%O_2 = formaldehyde concentration in gas stream corrected to 15% oxygen, ppmvd
C_{sm} = measured concentration of formaldehyde in the spiked aliquot
C_u = measured concentration of formaldehyde in the unspiked aliquot of the same sample
C_s = calculated concentration of formaldehyde spiking solution added to the spiked aliquot
F = dilution factor, 1 unless dilution of the sample was needed to reduce the absorbance into the calibration range
F_d = dry basis F-factor from Method 19, dscf per million btu GCV_g = Gross calorific value (or higher heating value), btu per scf
K_c = spectrophotometer calibration factor, slope of the least square regression line, µg/absorbance (Note: Most spreadsheets are capable of calculating a least squares line.)
K_1 = 0.3855 °K/mm Hg for metric units, (17.65 °R/in.Hg for English units.)
MW = molecular weight, 30 g/g-mole, for formaldehyde 24.05 = mole specific volume constant, liters per g-mole
m = mass of formaldehyde in liquid sample, mg
P_{std} = Standard pressure, 760 mm Hg (29.92 in.Hg)
P_{bar} = Barometric pressure, mm Hg (in.Hg)
PD = Percent Difference
Q_e = exhaust flow rate, dscf per minute
Q_g = natural gas fuel flow rate, scf per minute
T_m = Average DGM absolute temperature, °K (°R).
T_{std} = Standard absolute temperature, 293 °K (528 °R).
t = sample time (minutes)
V_m = Dry gas volume as measured by the DGM, dcm (dcf).
$V_{m(std)}$ = Dry gas volume measured by the DGM, corrected to standard conditions of 1 atmosphere and 20 °C, dscm (dscf).
V_t = actual total volume of impinger catch/rinsate, mL
V_a = volume (2.0) of aliquot analyzed, mL
X_1 = first value
X_2 = second value
O_{2d} = oxygen concentration measured, percent by volume, dry basis
%R = percent recovery of spike
Z_u = volume fraction of unspiked (native) sample contained in the final spiked aliquot [*e.g.*, Vu/(Vu + Vs), where Vu + Vs should = 2.0 mL]
Z_s = volume fraction of spike solution contained in the final spiked aliquot [*e.g.*, Vs/(Vu + Vs)]
R = 0.02405 dscm per g-mole, for metric units at standard conditions of 1 atmosphere and 20 °C
Y = Dry Gas Meter calibration factor

12.2 Pretest Design

$$C_1 = \frac{B * t * D * 30}{24.05 * E} \qquad \text{Eq. 323-1}$$

12.3 Exhaust Flow Rate

$$Q = \frac{F_d Q_g GCV_g}{10^6}\left[\frac{20.9}{20.9 - O_{2d}}\right] \qquad \text{Eq. 323-2}$$

12.4 Percent Difference—(Applicable to Field and Lab Duplicates)

$$PD = \frac{(X_1 - X_2)}{\left(\frac{X_1 + X_2}{2}\right)} * 100 \qquad \text{Eq. 323-3}$$

12.5 Percent Recovery of Spike

$$\%R = \frac{(C_{sm} - Z_u C_u)}{Z_s C_s} * 100 \qquad \text{Eq. 323-4}$$

12.6 Mass of Formaldehyde in Liquid Sample

$$m = K_c * A * F\left(\frac{V_t}{V_a}\right)\left(\frac{1\ mg}{1000\ .g}\right) \qquad \text{Eq. 323-5}$$

12.7 Dry Gas Sample Volume Corrected to Standard Conditions

$$V_{m(std)} = \frac{(V_m Y T_{std} P_{bar})}{T_m P_{std}} \quad \text{Eq. 323-6}$$

$$= \frac{K_1 Y V_m P_{bar}}{T_m}$$

12.8 Formaldehyde Concentration in gas Stream

$$c_{form} = \frac{R}{MW}\left(\frac{m}{V_{m(std)}}\right)\left(\frac{1\,g}{1000\,mg}\right)\left(1\times10^{6}\,ppmv\right) \quad \text{Eq. 323-7}$$

12.9 Formaldehyde Concentration Corrected to 15% Oxygen

$$c_{form@15\%O_2} = c_{form} * \frac{(20.9-15)}{(2.9-O_{2d})} \quad \text{Eq. 323-8}$$

13.0 Method Performance

13.1 Precision. Based on a Method 301 validation using quad train arrangement with post sampling spiking study of the method at a natural gas-fired IC engine, the relative standard deviation of six pairs of unspiked samples was 11.2 percent at a mean stack gas concentration of 16.7 ppmvd.

13.2 Bias. No bias correction is allowed. The single Method 301 validation study of the method at a natural gas-fired IC engine, indicated a bias correction factor of 0.91 for that set of data. An earlier spiking study got similar average percent spike recovery when spiking into a blank sample. This data set is too limited to justify using a bias correction factor for future tests at other sources.

13.3 Range. The range of this method for formaldehyde is 0.2 to 7.5 μg/mL in the liquid phase. (This corresponds to a range of 0.27 to 10 ppmv in the engine exhaust if sampling at a rate of 0.4 Lpm for 60 minutes and using a 40-mL VOA bottle.) If the liquid sample concentration is above this range, perform the appropriate dilution for accurate measurement. Any dilutions must be taken from new aliquots of the original sample before reanalysis.

13.4 Sample Stability. Based on a sample stability study conducted in conjunction with the method validation, sample degradation for 7- and 14-day hold times does not exceed 2.3 and 4.6 percent, respectively, based on a 95 percent level of confidence. Therefore, the recommended maximum sample holding time for the underivatized impinger catch/rinsings is 14 days, where projected sample degradation is below 5 percent.

14.0 Pollution Prevention

Sample gas from the combustion source exhaust is vented to the atmosphere after passing through the chilled impinger sampling train. Reagent solutions and samples should be collected for disposal as aqueous waste.

15.0 Waste Management

Standards of formaldehyde and the analytical reagents should be handled according to the Material Safety Data Sheets.

16.0 References

1. National Council of the Paper Industry for Air and Stream Improvement, Inc. "Volatile Organic Emissions from Pulp and Paper Mill Sources, Part X—Test Methods, Quality Assurance/Quality Control Procedures, and Data Analysis Protocols." Technical Bulletin No. 684, December 1994.

2. National Council of the Paper Industry for Air and Stream Improvement, Inc., "Field Validation of a Source Sampling Method for Formaldehyde, Methanol, and Phenol at Wood Products Mills." 1997 TAPPI International Environmental Conference.

3. Roy F. Weston, Inc. "Formaldehyde Sampling Method Field Evaluation and Emission Test Report for Georgia-Pacific Resins, Inc., Russellville, South Carolina." August 1996.

4. Hoechst Celanese Method CL 8–4. "Standard Test Method for Free Formaldehyde in Air Using Acetyl Acetone." Revision 0, September 1986.

5. Shareef, G.S., *et al.* "Measurement of Air Toxic Emissions from Natural Gas-Fired Internal Combustion Engines at Natural Gas Transmission and Storage Facilities." Report No. GRI–96/0009.1, Gas Research Institute, Chicago, Illinois, February 1996.

6. Gundappa, M., *et al.* "Characteristics of Formaldehyde Emissions from Natural Gas-Fired Reciprocating Internal Combustion Engines in Gas Transmission. Volume I: Phase I Predictive Model for Estimating Formaldehyde Emissions from 2–Stroke Engines." Report No. GRI–97/0376.1, Gas Research Institute, Chicago, Illinois, September 1997.

17.0 Tables, Diagrams, Flowcharts, and Validation Data

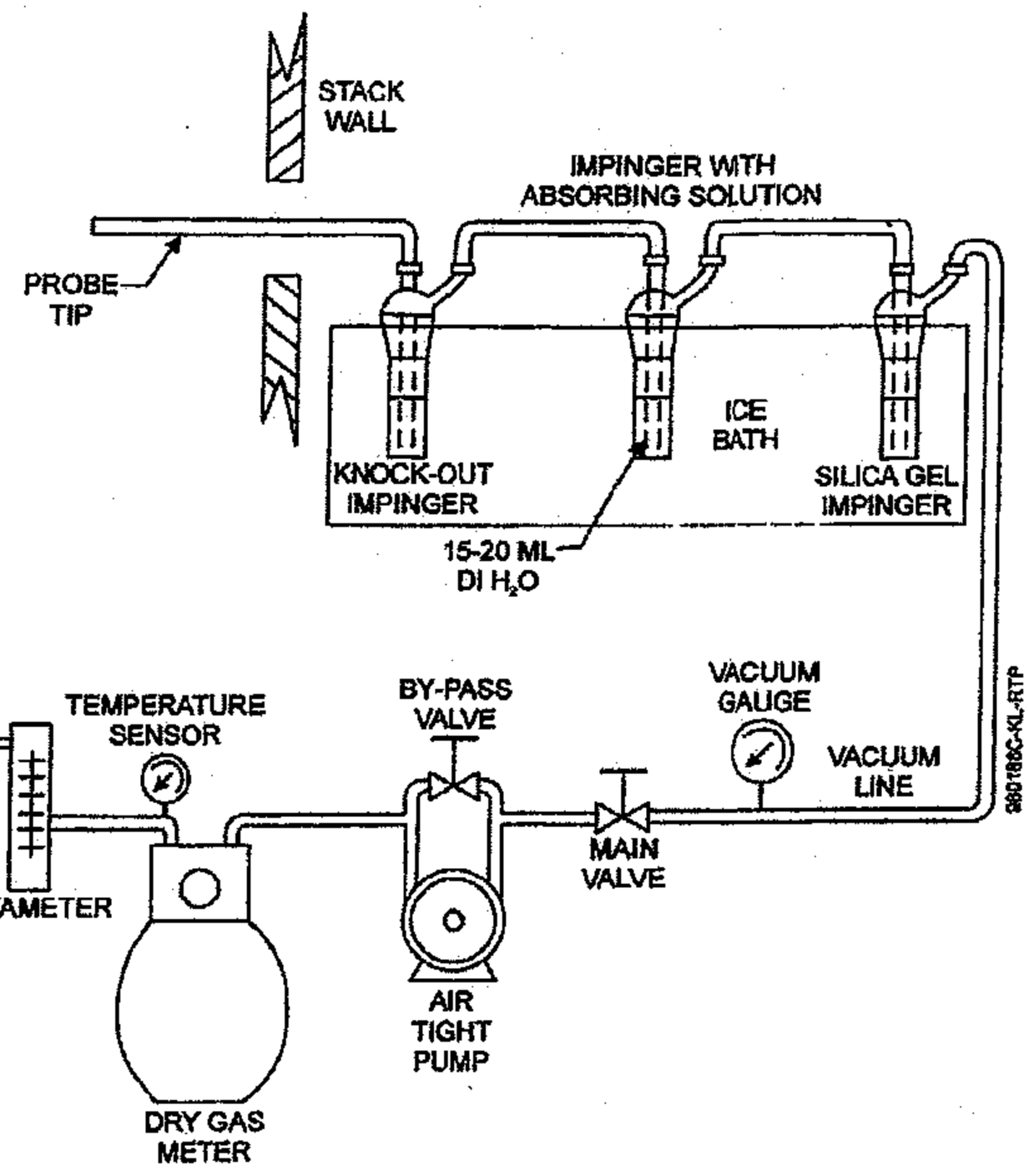


Figure 323-1. Chilled Impinger Train Sampling System

[FR Doc. 2010–20298 Filed 8–19–10; 8:45 am]

BILLING CODE 6560–50–P

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[FR Doc. 2010–15889 Filed 6–29–10; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2008–0708, FRL–9169–6]

RIN 2060–AP36

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; correction.

SUMMARY: EPA published in the **Federal Register** on March 3, 2010, a document amending the national emission standards for hazardous air pollutants for existing stationary compression ignition reciprocating internal combustion engines. The amendments inadvertently removed paragraphs from the regulation. EPA is correcting this error.

DATES: Effective on June 30, 2010.

FOR FURTHER INFORMATION CONTACT: Ms. Melanie King, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541–2469; facsimile number (919) 541–5450; e-mail address *king.melanie@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Summary of Amendments

EPA published in the **Federal Register** on March 3, 2010 (75 FR 9674) a document amending the national emission standards for hazardous air pollutants for existing stationary compression ignition reciprocating internal combustion engines. 40 CFR 63.6590 was amended by revising paragraphs (b)(1) and (3). Inadvertently, paragraphs (b)(1)(i) and (ii) of section 63.6590(b)(1) were removed. This correction amends section 63.6590 by reinstating paragraphs 63.6590(b)(1)(i) and (ii).

Section 553 of the Administrative Procedure Act (APA), 5 U.S.C. 553(b)(3)(B), provides that, when an Agency for good cause finds that notice and public procedure are impracticable, unnecessary, or contrary to the public interest, the Agency may issue a rule without providing notice and an opportunity for public comment. We have determined that there is good cause for making this technical correction final without prior proposal and opportunity for comment because this action only corrects a simple and obvious instructional error that would cause a change that was clearly not intended by the Agency in the final rule, as indicated by the preamble to the final rule. Thus, notice and public procedure is unnecessary. We find that this constitutes good cause under 5 U.S.C. 553(b)(3)(B). (*See also* the final sentence of section 307(d)(1) of the Clean Air Act (CAA), 42 U.S.C. 307(d)(1), indicating that the good cause provisions in subsection 553(b) of the APA continue to apply to this type of rulemaking under section 307(d) of the CAA.)

II. Statutory and Executive Order Reviews

Under Executive Order 12866, Regulatory Planning and Review (58 FR 51735, October 4, 1993), this action is not a "significant regulatory action" and is therefore not subject to review by the Office of Management and Budget. This action is not a "major rule" as defined by 5 U.S.C. 804(2). The correction does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

Because EPA has made a "good cause" finding that this action is not subject to notice and comment requirements under the APA or any other statute (*see* Section I of this preamble), it is not subject to the regulatory flexibility provisions of the Regulatory Flexibility Act [5 U.S.C. 601 *et seq.*], or to sections 202 and 205 of the Unfunded Mandates Reform Act of 1995 (UMRA) [Pub. L. 104–4]. In addition, this action does not significantly or uniquely affect small governments or impose a significant intergovernmental mandate, as described in sections 203 and 204 of the UMRA.

This action does not have substantial direct effects on the States, or 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, Federalism (64 FR 43255, August 10, 1999).

This action does not significantly or uniquely affect the communities of Tribal governments, as specified by Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (65 FR 67249, November 9, 2000). This action also is not subject to Executive Order 13045, Protection of Children from Environmental Health and Safety Risks (62 FR 19885, April 23, 1997) because it is not economically significant.

This action 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 this action is not a significant regulatory action under Executive Order 12866.

This action does not involve changes to the technical standards related to test methods or monitoring requirements; thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272) do not apply.

This action also does not involve special consideration of environmental justice-related issues as required by Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (59 FR 7629, February 16, 1994).

The Congressional Review Act (CRA), 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 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 U.S. Section 808 allows the issuing Agency to make a rule effective sooner than otherwise provided by the CRA if the Agency makes a good cause finding that notice and public procedure is impracticable, unnecessary, or contrary to the public interest. This determination must be supported by a brief statement. 5 U.S.C. 808(2). As stated previously, we have determined that there is good cause for making this correction final without prior proposal and opportunity for comment because this action only corrects a simple and obvious instructional error that would cause a change that was clearly not intended by the Agency in the final rule, as indicated by the preamble to the final rule. Thus, notice and public procedure is unnecessary. EPA has therefore established an effective date of June 30, 2010. The EPA will submit a report containing this final action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of this action in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). The final rule is effective June 30, 2010.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure,

Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: June 24, 2010.

Lisa P. Jackson,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

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

Subpart A—[Amended]

■ 2. Section 63.6590 is amended by revising paragraph (b)(1) to read as follows:

§ 63.6590 What parts of my plant does this subpart cover?

* * * * *

(b) * * *

(1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

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[FR Doc. 2010–15886 Filed 6–29–10; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 80

[EPA–HQ–OAR–2005–0161; FRL–9169–9]

RIN 2060–AQ31

Regulation of Fuels and Fuel Additives: Modifications to Renewable Fuel Standard Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Partial withdrawal of direct final rule.

SUMMARY: EPA published a direct final rule to amend the Renewable Fuel Standard program requirements on May 10, 2010. Because EPA received adverse comment, we are withdrawing several provisions of the direct final rule.

DATES: Effective June 30, 2010, EPA withdraws the definitions of "actual peak capacity," "baseline volume," and "permitted capacity" from 40 CFR 80.1401, and the amendments to 40 CFR 80.1403(a), 80.1425 introductory text and paragraph (i), 80.1426(d)(1) introductory text, 80.1426 Table 2, 80.1426(f)(3)(iv), 80.1426(f)(3)(v), 80.1426(f)(12), 80.1452(b) introductory text, (b)(2), (b)(4), (b)(6), (b)(9), (b)(13), and (b)(15), and 80.1452(c) introductory text, (c)(4), (c)(5), and (c)(7), that were published at 75 FR 26026 on May 10, 2010.

FOR FURTHER INFORMATION CONTACT: Megan Brachtl, Compliance and Innovative Strategies Division, Office of Transportation and Air Quality (Mail Code: 6405J), Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; telephone number: (202) 343–9473; fax number: (202) 343–2802; e-mail address: *brachtl.megan@epa.gov.*

SUPPLEMENTARY INFORMATION: Because EPA received adverse comment, we are withdrawing several provisions of the direct final rule to amend the Renewable Fuel Standard program requirements, published on May 10, 2010. We stated in that direct final rule that if we received adverse comment by June 9, 2010, the portion of the direct final rule on which adverse comment was received would not take effect, and we would publish a timely withdrawal of such portions of the direct final rule in the **Federal Register**.

We subsequently received adverse comment on the following provisions: Certain of the amendments to 40 CFR 80.1401 (moved the definitions of "actual peak capacity," "baseline volume," and "permitted capacity" from 40 CFR 80.1403(a), revised the definition of "actual peak capacity" to clarify how it is calculated and revised the definition of "permitted capacity" to clarify the dates before which permits used to establish a facility's permitted capacity must have been issued or revised); 40 CFR 80.1425 (clarified that RINs generated after July 1, 2010, may only be generated and transferred using the EPA-Moderated Transaction System (EMTS) and will not be identified by a 38-digit code and that the value of EEEEEEEE in a batch-RIN will be determined by the number of gallon-RINs generated for the batch); 40 CFR 80.1426(d)(1), 80.1426(f)(3)(iv), and 80.1426(f)(3)(v) (clarified that a unique BBBBB code in the RIN, or its equivalent in EMTS, is used to identify a batch of renewable fuel from a given renewable fuel producer or importer); 40 CFR 80.1426 Table 2 (clarified the extent to which renewable fuel producers must use certain advanced technologies in order for them to be considered when determining the proper D code for their fuel); 40 CFR 80.1426(f)(12) (clarified the requirements for gas to be considered biogas for purposes of determining a renewable fuel's D code); 40 CFR 80.1452(b) (clarified that RINs must be generated in EMTS within five (5) business days of being assigned to a batch of renewable fuel and clarified the information required to be submitted via EMTS for each batch of renewable fuel produced or imported); and, 40 CFR 80.1452(c) (clarified that transactions involving RINs generated on or after July 1, 2010 must be conducted via EMTS within five (5) business days of a reportable event, and clarified the meaning of the term "reportable event" and the information required to be submitted via EMTS for each transaction involving RINs generated on or after July 1, 2010).

EPA published a parallel proposed rule on the same day as the direct final rule. The proposed rule invited comment on the substance of the direct final rule. We will address the comments received on the portions of the direct final rule listed above in a subsequent final action based on the parallel proposed rule also published on May 10, 2010 (75 FR 26049). The provisions for which we did not receive adverse comment will become effective on July 1, 2010, as provided in the May 10, 2010, direct final rule.

Dated: June 24, 2010.

Lisa P. Jackson,

Administrator.

PART 80—REGULATION OF FUELS AND FUEL ADDITIVES

■ Accordingly, the definitions of "actual peak capacity," "baseline volume," and "permitted capacity" in 40 CFR 80.1401, and the amendments to 40 CFR 80.1403(a), 80.1425 introductory text and paragraph (i), 80.1426(d)(1) introductory text, 80.1426 Table 2, 80.1426(f)(3)(iv), 80.1426(f)(3)(v), 80.1426(f)(12), 80.1452(b) introductory text, (b)(2), (b)(4), (b)(6), (b)(9), (b)(13), and (b)(15), and 80.1452(c) introductory text, (c)(4), (c)(5), and (c)(7), that were published on May 10, 2010 (75 FR 26026) are withdrawn as of June 30, 2010.

[FR Doc. 2010–15881 Filed 6–29–10; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2008–0708, FRL–9115–7]

RIN 2060–AP36

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is promulgating national emission standards for hazardous air pollutants for existing stationary compression ignition reciprocating internal combustion engines that either are located at area sources of hazardous air pollutant emissions or that have a site rating of less than or equal to 500 brake horsepower and are located at major sources of hazardous air pollutant emissions. In addition, EPA is promulgating national emission standards for hazardous air pollutants for existing non-emergency stationary compression ignition engines greater than 500 brake horsepower that are located at major sources of hazardous air pollutant emissions. Finally, EPA is revising the provisions related to startup, shutdown, and malfunction for the engines that were regulated previously by these national emission standards for hazardous air pollutants.

DATES: This final rule is effective on May 3, 2010.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2008–0708. EPA also relies on materials in Docket ID Nos. EPA–HQ–OAR–2002–0059, EPA–HQ–OAR–2005–0029, and EPA–HQ–OAR–2005–0030 and incorporates those dockets into the record for the final rule. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, Confidential Business Information (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 *http://www.regulations.gov* or in hard copy at the EPA Headquarters Library, Room Number 3334, EPA West Building, 1301 Constitution Ave., NW., Washington, DC. The EPA/DC Public Reading Room hours of operation will be 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket and Information Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Melanie King, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541–2469; facsimile number (919) 541–5450; e-mail address *king.melanie@epa.gov*.

SUPPLEMENTARY INFORMATION:

Background Information Document. On March 5, 2009 (71 FR 9698), EPA proposed national emission standards for hazardous air pollutants (NESHAP) for existing stationary reciprocating internal combustion engines (RICE) that either are located at area sources of hazardous air pollutants (HAP) emissions or that have a site rating of less than or equal to 500 brake horsepower (HP) and are located at major sources of HAP emissions. In addition, EPA proposed national emission standards for HAP for existing stationary compression ignition (CI) engines greater than 500 brake HP that are located at major sources. A summary of the public comments on the proposal and EPA's responses to the comments, as well as the Regulatory Impact Analysis Report, are available in Docket ID No. EPA–HQ–OAR–2008–0708.

Organization of This Document. The following outline is provided to aid in locating information in the preamble.

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K. Congressional Review Act

I. General Information

A. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action include:

Category	NAICS [1]	Examples of regulated entities
Any industry using a stationary internal combustion engine as defined in this final rule.	2211	Electric power generation, transmission, or distribution.
	622110	Medical and surgical hospitals.
	48621	Natural gas transmission.
	211111	Crude petroleum and natural gas production.
	211112	Natural gas liquids producers.

Category	NAICS [1]	Examples of regulated entities
	92811	National security.

[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 engine is regulated by this action, you should examine the applicability criteria of this final rule. 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.

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 this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by May 3, 2010. Under section 307(d)(7)(B) of the CAA, only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to 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. Why is EPA not promulgating a final decision for spark ignition engines?

In the notice of proposed rulemaking for this rule, published on March 5, 2009, EPA proposed the NESHAP for all existing stationary RICE located at area sources of HAP emissions and existing stationary RICE that had a site rating of less than or equal to 500 brake HP and located at major sources of HAP emissions. Also, EPA proposed NESHAP for existing stationary CI engines greater than 500 brake HP located at major sources.

During the comment period following the proposal, EPA received a number of comments stating that EPA had insufficient emissions data for existing spark ignition (SI) engines. Because commenters believed that EPA had inadequate emissions data for SI engines, they suggested that EPA should consider seeking an extension of its February 10, 2010 consent decree deadline to allow additional time for the collection of emissions data for SI engines. Several commenters indicated that they would work with EPA to gather the necessary test data to obtain adequate and sufficient emissions tests for SI engines. Among other things, the commenters noted that developing the final requirements for SI engines later in 2010 would provide sufficient time for industry to develop test programs, conduct testing of engines, assemble test results, and submit the complete results to EPA for review. Other commenters requested that EPA seek a one year extension of its consent decree deadline for SI engines, which would mean a final rule for these engines by February 10, 2011.

In consideration of the comments, EPA sought and obtained a six month extension of its February 10, 2010 deadline for SI engines. EPA maintains that this period is sufficient for the commenters to provide additional test data for the SI engines. Thus, pursuant to the revised consent decree between EPA and Sierra Club, EPA will finalize requirements for existing stationary SI engines that are less than or equal to 500 HP and located at major sources of HAP emissions and existing stationary SI engines that are located at area sources of HAP emissions by August 10, 2010. For these reasons, this final rule does not contain standards for existing stationary SI engines that are less than or equal to 500 HP and located at major sources of HAP emissions and existing stationary SI engines that are located at area sources of HAP emissions.

Consistent with the original consent decree, EPA is finalizing regulations for existing stationary CI engines that are less than or equal to 500 HP and located at major sources and existing stationary CI engines that are located at area sources in this final rule. EPA is also promulgating requirements for existing stationary non-emergency CI engines that are greater than 500 HP and located at major sources.

EPA plans to continue to work with affected stakeholders over the next several months in order to obtain more complete emissions data for existing stationary SI engines. The emissions data collected will be analyzed and if EPA's review indicates that the submitted data meets acceptance criteria, EPA will include the data in developing final standards. EPA will promulgate regulations for existing stationary SI engines by August 10, 2010.

II. Background

This action promulgates NESHAP for existing stationary CI RICE with a site rating of less than or equal to 500 HP located at major sources, existing non-emergency CI engines with a site rating greater than 500 HP at major sources, and existing stationary CI RICE of any power rating located at area sources. EPA is finalizing these standards to meet its statutory obligation to address HAP emissions from these sources under sections 112(d), 112(c)(3) and 112(k) of the CAA. The final NESHAP for stationary RICE will be promulgated

under 40 CFR part 63, subpart ZZZZ, which already contains standards applicable to new stationary RICE and some existing stationary RICE.

EPA promulgated NESHAP for existing, new, and reconstructed stationary RICE greater than 500 HP located at major sources on June 15, 2004 (69 FR 33474). EPA promulgated NESHAP for new and reconstructed stationary RICE that are located at area sources of HAP emissions and for new and reconstructed stationary RICE that have a site rating of less than or equal to 500 HP that are located at major sources of HAP emissions on January 18, 2008 (73 FR 3568). At that time, EPA did not promulgate final requirements for existing stationary RICE that are located at area sources of HAP emissions or for existing stationary RICE that have a site rating of less than or equal to 500 HP that are located at major sources of HAP emissions. Although EPA proposed standards for these sources, EPA did not finalize these standards due to comments received indicating that the proposed Maximum Achievable Control Technology (MACT) determinations for existing sources were inappropriate because of a decision by the U.S. Court of Appeals for the District of Columbia Circuit on March 13, 2007, which vacated EPA's MACT standards for the Brick and Structural Clay Products Manufacturing source category (40 CFR part 63, subpart JJJJJ). *Sierra Club* v. *EPA*, 479 F.3d 875 (DC Cir. 2007). Among other things, the DC Circuit found that EPA's no emission reduction MACT determination in the challenged rule was unlawful. Because EPA had used a MACT floor methodology in the proposed stationary RICE rule similar to the methodology used in the Brick MACT, EPA decided to re-evaluate the MACT floors for existing major sources that have a site rating of less than or equal to 500 brake HP consistent with the Court's decision in the Brick MACT case. Also, EPA has re-evaluated the standards for existing area sources in light of the comments received on the proposed rule.

In addition, stakeholders have encouraged the Agency to review whether there are further ways to reduce emissions of pollutants from existing stationary diesel engines. In its comments on EPA's 2005 proposed rule for new stationary diesel engines (70 FR 39870), the Environmental Defense Fund (EDF) suggested several possible avenues for the regulation of existing stationary diesel engines, including use of diesel oxidation catalysts or catalyzed diesel particulate filters (CDPF), as well as the use of ultra low sulfur diesel (ULSD) fuel. EDF suggested that such controls can provide significant pollution reductions at reasonable cost. EPA issued an advance notice of proposed rulemaking (ANPRM) in January 2008, where it solicited comment on several issues concerning options to regulate emissions of pollutants from existing stationary diesel engines, generally, and specifically from larger, older stationary diesel engines. EPA solicited comment and collected information to aid decision-making related to the reduction of HAP emissions from existing stationary diesel engines and specifically from larger, older engines under CAA section 112 authorities. The Agency sought comment on the larger, older non-emergency CI engines because available data indicate that those engines emit the majority of particulate matter (PM) and toxic emissions from non-emergency stationary CI engines as a whole. A summary of comments and responses that were received on the ANPRM is included in docket EPA–HQ–OAR–2007–0995. EPA proposed and is finalizing emissions reductions from existing non-emergency stationary diesel engines at major sources that have a site rating greater than 500 HP.

This action also revises the provisions of the existing NESHAP as it applies to periods of startup, shutdown, and malfunction. This revision affects all stationary engines regulated in this NESHAP, including stationary engines that were regulated by the 2004 and 2008 NESHAP. The revision of these provisions is a result of a Court decision that invalidated regulations related to startup, shutdown and malfunction in the General Provisions of Part 63 (*Sierra Club* v. *EPA*, 551 F.3d 1019 (DC Cir. 2008)).

III. Summary of the Final Rule

A. What is the source category regulated by the final rule?

This final rule addresses emissions from existing stationary CI engines less than or equal to 500 HP located at major sources and all existing stationary CI engines located at area sources. This final rule also addresses emissions from existing stationary non-emergency CI engines greater than 500 HP at major sources. A major source of HAP emissions is generally a stationary source that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year. An area source of HAP emissions is a source that is not a major source.

This action revises the regulations at 40 CFR part 63, subpart ZZZZ, currently applicable to new and reconstructed stationary RICE and to existing stationary RICE greater than 500 HP located at major sources. Through this action, we are adding to subpart ZZZZ requirements for: Existing CI stationary RICE less than or equal to 500 HP located at major sources and existing CI stationary RICE located at area sources.

1. Stationary CI RICE ≤500 HP at Major Sources

This action revises 40 CFR part 63, subpart ZZZZ, to address HAP emissions from existing stationary CI RICE less than or equal to 500 HP located at major sources. For stationary engines less than or equal to 500 HP at major sources, EPA must determine what is the appropriate MACT for those engines under sections 112(d)(2) and (d)(3) of the CAA.

EPA has divided stationary CI RICE into emergency and non-emergency engines in order to capture the unique differences between these types of engines.

2. Stationary CI RICE at Area Sources

This action revises 40 CFR part 63, subpart ZZZZ, in order to address HAP emissions from existing stationary RICE located at area sources. Section 112(d) of the CAA requires EPA to establish NESHAP for both major and area sources of HAP that are listed for regulation under CAA section 112(c). As noted above, an area source is a stationary source that is not a major source.

Section 112(k)(3)(B) of the CAA calls for EPA to identify at least 30 HAP that, as a result of emissions of area sources, pose the greatest threat to public health in the largest number of urban areas. EPA implemented this provision in 1999 in the Integrated Urban Air Toxics Strategy (64 FR 38715, July 19, 1999). Specifically, in the Strategy, EPA identified 30 HAP that pose the greatest potential health threat in urban areas, and these HAP are referred to as the "30 urban HAP." Section 112(c)(3) of the CAA requires EPA to list sufficient categories or subcategories of area sources to ensure that area sources representing 90 percent of the emissions of the 30 urban HAP are subject to regulation. EPA implemented these requirements through the Integrated Urban Air Toxics Strategy (64 FR 38715, July 19, 1999). The area source stationary engine source category was one of the listed categories. A primary goal of the Strategy is to achieve a 75 percent reduction in cancer incidence attributable to HAP emitted from stationary sources.

Under CAA section 112(d)(5), EPA may elect to promulgate standards or requirements for area sources "which provide for the use of generally available control technologies or management practices by such sources to reduce emissions of hazardous air pollutants." Additional information on generally available control technologies (GACT) and management practices is found in the Senate report on the legislation (Senate report Number 101–228, December 20, 1989), which describes GACT as:

> * * * methods, practices and techniques which are commercially available and appropriate for application by the sources in the category considering economic impacts and the technical capabilities of the firms to operate and maintain the emissions control systems.

Consistent with the legislative history, EPA can consider costs and economic impacts in determining GACT, which is particularly important when developing regulations for source categories, like this one, that have many small businesses.

Determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. EPA also considers the standards applicable to major sources in the same industrial sector to determine if the control technologies and management practices are transferable and generally available to area sources. In appropriate circumstances, EPA may also consider technologies and practices at area and major sources in similar categories to determine whether such technologies and practices could be considered generally available for the area source category at issue. Finally, as EPA has already noted, in determining GACT for a particular area source category, EPA considers the costs and economic impacts of available control technologies and management practices on that category.

The urban HAP that must be regulated at stationary RICE to achieve the CAA section 112(c)(3) requirement to regulate categories accounting for 90 percent of the urban HAP are: 7 polycyclic aromatic hydrocarbons (PAH), formaldehyde, acetaldehyde, arsenic, benzene, beryllium compounds, and cadmium compounds. As explained below, EPA chose to select formaldehyde to serve as a surrogate for HAP emissions. Formaldehyde is the hazardous air pollutant present in the highest concentration from stationary engines. In addition, emissions data show that formaldehyde emission levels are related to other HAP emission levels. EPA has previously demonstrated that carbon monoxide (CO) is an appropriate surrogate for formaldehyde and is consequently finalizing emission standards in terms of CO for existing stationary CI RICE at area sources.

Consistent with existing stationary CI RICE at major sources, EPA has also divided the existing stationary CI RICE at area sources into emergency and non-emergency engines in order to properly take into account the differences between these engines.

3. Stationary CI RICE > 500 HP at Major Sources

In addition, EPA is finalizing emission standards for non-emergency stationary CI engines greater than 500 HP at major sources.

B. What are the pollutants regulated by the final rule?

The final rule regulates emissions of HAP. Available emissions data show that several HAP, which are formed during the combustion process or which are contained within the fuel burned, are emitted from stationary engines. The HAP which have been measured in emission tests conducted on diesel fired stationary RICE include: 1, 3-butadiene, acetaldehyde, acrolein, benzene, ethylbenzene, formaldehyde, n-hexane, naphthalene, PAH, polycyclic organic matter, styrene, toluene, and xylene. Metallic HAP from diesel fired stationary RICE that have been measured include: Cadmium, chromium, lead, manganese, mercury, nickel, and selenium.

EPA described the health effects of these HAP and other HAP emitted from the operation of stationary RICE in the preamble to 40 CFR part 63, subpart ZZZZ, published on June 15, 2004 (69 FR 33474). More detail on the health effects of these HAP and other HAP emitted from the operation of stationary RICE can be found in the Regulatory Impact Analysis (RIA) for the final rule. These HAP emissions are known to cause, or contribute significantly to air pollution, which may reasonably be anticipated to endanger public health or welfare.

The final rule will limit emissions of HAP through emissions standards for CO for existing stationary CI RICE. Carbon monoxide has been shown to be an appropriate surrogate for HAP emissions from CI engines. For the NESHAP promulgated in 2004, EPA found that there is a relationship between CO emissions reductions and HAP emissions reductions from CI stationary engines. Therefore, because testing for CO emissions has many advantages over testing for HAP emissions, CO emissions were chosen as a surrogate for HAP emissions reductions for CI stationary engines.

For the standards being finalized in this action, EPA believes that previous decisions regarding the appropriateness of using CO in concentration (parts per million (ppm)) levels as has been done for stationary sources before as surrogates for HAP are still valid.[1] Consequently, EPA is finalizing emission standards for CO for stationary CI engines in order to regulate HAP emissions. In addition, EPA is promulgating separate provisions relevant to emissions of metallic HAP from existing diesel engines, as discussed in section III.C. of this preamble.

In addition to reducing HAP and CO, the final rule will result in the reduction of PM emissions from existing stationary diesel engines. The aftertreatment technologies expected to be used to reduce HAP and CO emissions also reduce emissions of PM from diesel engines. Also, the final rule requires the use of ULSD for diesel-fueled stationary non-emergency CI engines greater than 300 HP with a displacement of less than 30 liters per cylinder. This will result in lower emissions of sulfur oxides (SO_X) and sulfate particulate from these engines by reducing the sulfur content in the fuel.

C. What are the final requirements?

1. Existing Stationary RICE at Major Sources.

The numerical emission standards that are being finalized in this action for stationary non-emergency CI RICE located at major sources are shown in Table 1 of this preamble. The numerical emission standards are in units of ppm by volume, dry basis (ppmvd) or percent reduction.

[1] In contrast, mobile source emission standards for diesel engines (both nonroad and on-highway) are promulgated on a mass/bhp-hr basis rather than concentration.

TABLE 1—NUMERICAL EMISSION STANDARDS FOR EXISTING STATIONARY CI RICE LOCATED AT MAJOR SOURCES

Subcategory	Except during periods of startup
Non-Emergency CI 100≤HP≤300	230 ppmvd CO at 15% O_2.
Non-Emergency CI 300<HP≤500	49 ppmvd CO at 15% O_2 or 70% CO reduction.
Non-Emergency CI >500 HP	23 ppmvd CO at 15% O_2 or 70% CO reduction.

In addition, certain existing stationary RICE located at major sources are subject to fuel requirements. Owners and operators of existing stationary non-emergency CI engines greater than 300 HP with a displacement of less than 30 liters per cylinder located at major sources that use diesel fuel must use only diesel fuel meeting the requirements of 40 CFR 80.510(b). This section requires that diesel fuel have a maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent. These fuel requirements are being finalized in order to reduce the potential formation of sulfate compounds that are emitted when high sulfur diesel fuel is used in combination with oxidation catalysts and to assist in the efficient operation of the oxidation catalysts.

EPA is finalizing work practice standards for existing stationary emergency CI RICE less than or equal to 500 HP located at major sources and existing stationary non-emergency CI RICE less than 100 HP located at major sources. Existing stationary emergency CI RICE less than or equal to 500 HP located at major sources are subject to the following work practices:

- Change oil and filter every 500 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and none of the condemning limits are exceeded;
- Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and
- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

Existing stationary non-emergency CI RICE less than 100 HP located at major sources are subject to the following work practices:

- Change oil and filter every 1,000 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and none of the condemning limits are exceeded;
- Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and
- Inspect all hoses and belts every 500 hours or annually, whichever comes first, and replace as necessary.

Sources also have the option to use an oil change analysis program to extend the oil change frequencies specified above. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The analysis must be conducted at the same frequencies specified for changing the engine oil. If the condemning limits provided below are not exceeded, the engine owner or operator is not required to change the oil. If any of the condemning limits are exceeded, the engine owner or operator must change the oil before continuing to use the engine. The condemning limits are as follows:

- Total Base Number is less than 30 percent of the Total Base Number of the oil when new; or
- Viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or
- Percent water content (by volume) is greater than 0.5.

Pursuant to the provisions of 40 CFR 63.6(g), sources can also request that the Administrator approve alternative work practices.

EPA is also including in the final rule additional capture and collection requirements to reduce metallic HAP emissions. Owners and operators of existing stationary non-emergency CI engines greater than 300 HP located at major sources must do one of the following if the engine is not already equipped with a closed crankcase ventilation system: (1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or (2) install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

2. Existing Stationary RICE at Area Sources

The numerical emission standards that are being finalized in this action for stationary CI RICE located at area sources are shown in Table 2 of this preamble. Existing stationary emergency engines at area sources located at residential, commercial, or institutional facilities are not part of the source category and therefore are not subject to any requirements under this final rule.

Although existing stationary non-emergency CI RICE greater than 300 HP that are located at area sources in Alaska that are not accessible by the Federal Aid Highway System (FAHS) do not have to meet the CO emission standards specified in Table 2 of this preamble, they must meet the management practices discussed in this section for non-emergency CI RICE less than or equal to 300 HP.

TABLE 2—NUMERICAL EMISSION STANDARDS FOR EXISTING STATIONARY RICE LOCATED AT AREA SOURCES

Subcategory	Except during periods of startup
Non-Emergency CI 300<HP≤500	49 ppmvd CO at 15% O_2 or 70% CO reduction.
Non-Emergency CI>500 HP	23 ppmvd CO at 15% O_2 or 70% CO reduction.

Also, owners and operators of existing stationary non-emergency CI engines greater than 300 HP with a displacement of less than 30 liters per cylinder located at area sources that use diesel fuel must use only diesel fuel meeting the requirements of 40 CFR 80.510(b). This section requires that diesel fuel have a maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

EPA is finalizing management practices for existing stationary emergency CI RICE located at area sources and existing stationary non-emergency CI RICE less than or equal to 300 HP located at area sources. Existing stationary emergency CI RICE located at area sources are subject to the following management practices:

- Change oil and filter every 500 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and the condemning limits are not exceeded;
- Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and
- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

Existing stationary non-emergency CI RICE less than or equal to 300 HP located at area sources are subject to the following management practices:

- Change oil and filter every 1,000 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and the condemning limits are not exceeded;
- Inspect air cleaner every 1000 hours of operation or annually, whichever comes first; and
- Inspect all hoses and belts every 500 hours or annually, whichever comes first, and replace as necessary.

As discussed above for major sources, these sources may utilize an oil analysis program in order to extend the specified oil change requirement specified above. Also, sources have the option to work with State permitting authorities pursuant to EPA's regulations at 40 CFR subpart E ("Approval of State Programs and Delegation of Federal Authorities") for approval of alternative management practices. Subpart E implements section 112(l) of the CAA, which authorizes EPA to approve alternative State/local/Tribal HAP standards or programs when such requirements are demonstrated to be no less stringent than EPA promulgated standards.

Finally, in order to reduce metallic HAP emissions, existing stationary non-emergency CI engines greater than 300 HP located at area sources must do one of the following if the engine is not already equipped with a closed crankcase ventilation system: (1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or (2) install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

3. Startup Requirements

The following stationary engines are subject to specific operational standards during engine startup:

- Existing CI RICE less than or equal to 500 HP located at major sources,
- Existing non-emergency CI RICE greater than 500 HP located at major sources,
- Existing CI RICE located at area sources,
- New or reconstructed non-emergency two-stroke lean burn (2SLB) >500 HP located at a major source of HAP emissions,
- New or reconstructed non-emergency four-stroke lean burn (4SLB) >=250 HP located at a major source of HAP emissions,
- Existing non-emergency four-stroke rich burn (4SRB) >500 HP located at a major source of HAP emissions,
- New or reconstructed non-emergency 4SRB >500 HP located at a major source of HAP emissions, and
- New or reconstructed non-emergency CI >500 HP located at a major source of HAP emissions.

Engine startup is defined as the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engines with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state, or normal operation, including the catalyst. Owners and operators must minimize the engine's time spent at idle and minimize the engine's startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the engine must meet the otherwise applicable emission standards. These requirements will limit the HAP emissions during periods of engine startup. Pursuant to the provisions of 40 CFR 63.6(g), engines at major sources may petition the Administrator for an alternative work practice. An owner or operator of an engine at an area source can work with its State permitting authority pursuant to EPA's regulations at 40 CFR subpart E for approval of an alternative management practice. *See* 40 CFR Subpart E (setting forth requirements for, among other things, equivalency by permit, rule substitution).

D. What are the operating limitations?

In addition to the standards discussed above, EPA is finalizing operating limitations for stationary non-emergency CI RICE that are greater than 500 HP. Owners and operators of engines that are equipped with oxidation catalyst must maintain the catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test. Owners and operators of these engines must also maintain the temperature of the stationary RICE exhaust so that the catalyst inlet temperature is between 450 and 1350 degrees Fahrenheit (°F). Owners and operators may petition for a different temperature range; the petition must demonstrate why it is operationally necessary and appropriate to operate below the temperature range specified in the rule (*see* 40 CFR 63.8(f)). Owners and operators of engines that are not using oxidation catalyst must comply with any operating limitations approved by the Administrator.

Owners and operators of existing stationary non-emergency CI engines greater than 300 HP meeting the requirement to use open or closed crankcases must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements.

E. What are the requirements for demonstrating compliance?

The following sections describe the requirements for demonstrating compliance under the final rule.

1. Existing Stationary CI RICE at Major Sources

Owners and operators of existing stationary non-emergency CI RICE located at major sources that are less than 100 HP and stationary emergency CI RICE located at major sources must operate and maintain their stationary RICE and aftertreatment control device (if any) according to the manufacturer's emission-related written instructions or develop their own maintenance plan. Owners and operators of existing stationary non-emergency CI RICE located at major sources that are less than 100 HP and existing stationary emergency CI RICE located at major sources do not have to conduct any

performance testing because they are not subject to numerical emission standards.

Owners and operators of existing stationary non-emergency CI RICE located at major sources that are greater than or equal to 100 HP and less than or equal to 500 HP must conduct an initial performance test to demonstrate that they are achieving the required emission standards.

Owners and operators of existing stationary non-emergency CI RICE greater than 500 HP located at major sources must conduct an initial performance test and must test every 8,760 hours of operation or 3 years, whichever comes first, to demonstrate that they are achieving the required emission standards.

Owners and operators of stationary non-emergency CI RICE that are greater than 500 HP and are located at a major source must continuously monitor and record the catalyst inlet temperature if an oxidation catalyst is being used on the engine. The pressure drop across the catalyst must also be measured monthly. If an oxidation catalyst is not being used on the engine, the owner or operator must continuously monitor and record the operating parameters (if any) approved by the Administrator.

On October 9, 2008 (73 FR 59956), EPA proposed performance specification requirements for continuous parametric monitoring systems (CPMS). Currently there are no performance specifications for the CPMS that are required for continuously monitoring the catalyst inlet temperature. The timetable for finalizing the proposed performance specification requirements is uncertain; therefore, EPA plans to finalize performance specification requirements in 40 CFR part 63, subpart ZZZZ for the CPMS systems used for continuous catalyst inlet temperature monitoring when the final requirements are promulgated for existing SI engines in August 2010.

2. Existing Stationary RICE at Area Sources

Owners and operators of existing stationary RICE located at area sources that are subject to management practices, as shown in Table 2 of this preamble, must develop a maintenance plan that specifies how the management practices will be met. Owners and operators of existing stationary RICE that are subject to management practices do not have to conduct any performance testing.

Owners and operators of existing stationary non-emergency CI RICE greater than 300 HP that are located at area sources must conduct an initial performance test to demonstrate that they are achieving the required emission standards.

Owners and operators of existing stationary non-emergency CI RICE that are greater than 500 HP and located at area sources and are not limited use stationary RICE must conduct an initial performance test and must test every 8,760 hours of operation or 3 years, whichever comes first, to demonstrate that they are achieving the required emission standards. Owners and operators of existing stationary non-emergency CI RICE that are greater than 500 HP and located at area sources and are limited use stationary RICE must conduct an initial performance test and must test every 8,760 hours of operation or 5 years, whichever comes first, to demonstrate that they are achieving the required emission standards.

Owners and operators of existing stationary non-emergency CI RICE that are greater than 500 HP and are located at an area source must continuously monitor and record the catalyst inlet temperature if an oxidation catalyst is being used on the engine. The pressure drop across the catalyst must also be measured monthly. If an oxidation catalyst is not being used on the engine, the owner or operator must continuously monitor and record the operating parameters (if any) approved by the Administrator.

F. What are the reporting and recordkeeping requirements?

The following sections describe the reporting and recordkeeping requirements that are required under the final rule.

Owners and operators of existing stationary emergency RICE that do not meet the requirements for non-emergency engines are required to keep records of their hours of operation. Owners and operators of existing stationary emergency RICE must install a non-resettable hour meter on their engines to record the hours of operation of the engine. Emergency stationary RICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units are limited to 100 hours per year. There is no time limit on the use of emergency stationary engines in emergency situations; however, the owner or operator is required to record the length of operation and the reason the engine was in operation during that time. Records must be maintained documenting why the engine was operating to ensure the 100 hours per year limit for maintenance and testing operation is not exceeded. In addition, owners and operators are allowed to operate their stationary emergency RICE for non-emergency purposes for 50 hours per year, but those 50 hours are counted towards the total 100 hours provided for operation other than for true emergencies. The 50 hours per year for non-emergency purposes cannot be used to generate income for a facility, for example, to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. However, owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, for example unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. Owners and operators must keep records showing how they were notified of the emergency condition and by whom, and the time that the engine was operated as part of demand response.

Owners and operators of existing stationary CI RICE located at area sources that are subject to management practices as shown in Table 2 of this preamble are required to keep records that show that management practices that are required are being met. These records must include, at a minimum: Oil and filter change dates and corresponding hour on the hour meter; inspection and replacement dates for air cleaners, hoses, and belts; and records of other emission-related repairs and maintenance performed.

Owners and operators of existing non-emergency stationary CI RICE greater than 300 HP must keep records of the manufacturer's recommended maintenance procedures for the closed crankcase ventilation system or open crankcase filtration system and records of the maintenance performed on the system.

In terms of reporting requirements, owners and operators of existing stationary RICE, except stationary RICE that are less than 100 HP, existing emergency stationary RICE, and existing stationary RICE that are not subject to numerical emission standards, must submit all of the applicable notifications as listed in the NESHAP General Provisions (40 CFR part 63, subpart A), including an initial notification, notification of performance test, and a notification of compliance for each stationary RICE which must comply with the specified emission limitations.

IV. Summary of Significant Changes Since Proposal

Most of the rationale used to develop the proposed rule remains the same for the final rule. Therefore, the rationale previously provided in the preamble to the proposed rule is not repeated in the final rule, and the rationale sections of the rule, as proposed, should be referred to. Major changes that have been made to the rule since proposal are discussed in this section with rationale following in the Summary of Responses to Major Comments section.

A. Applicability

EPA proposed to regulate HAP emissions from existing stationary engines less than or equal to 500 HP located at major sources and all existing stationary engines located at area sources. EPA also proposed NESHAP for existing stationary non-emergency CI engines greater than 500 HP that are located at major sources.

In the final rule, EPA is only regulating HAP emissions from existing stationary CI engines. EPA will address HAP emissions from existing stationary SI engines in a separate rulemaking later this year.

Another change from the proposal is that the final rule is not applicable to existing stationary emergency engines at area sources that are located at residential, commercial, or institutional facilities. These engines are not subject to any requirements under the final rule because they are not part of the regulated source category. EPA has found that existing stationary emergency engines located at residential, commercial, and institutional facilities that are area sources were not included in the original Urban Air Toxics Strategy inventory and were not included in the listing of urban area sources. More information on this issue can be found in the memorandum entitled, "Analysis of the Types of Engines Used to Estimate the CAA Section 112(k) Area Source Inventory for Stationary Reciprocating Internal Combustion Engines," available from the rulemaking docket.

B. Final Emission Standards

1. Existing Stationary CI Engines <100 HP Located at Major Sources

For the proposed rule, EPA required existing stationary engines less than 50 HP that are located at major sources to meet a formaldehyde emission standard. EPA is not finalizing a formaldehyde emission standard for stationary CI engines less than 50 HP, but is instead requiring compliance with a work practice. In addition, in light of several comments asserting that the level at which we subcategorized small engines at major sources was inappropriate, EPA is finalizing a work practice standard for engines less than 100 HP.

In the proposed rule, existing stationary CI engines less than 100 HP located at major sources were required to meet a 40 ppmvd CO at 15 percent oxygen (O_2) standard. In the final rule, all existing stationary CI engines less than 100 HP located at major sources must meet work practices. These work practices are described in section III.C. of this preamble. EPA believes that work practices are appropriate and justified for this group of stationary engines because the application of measurement methodology is not practicable due to technological and economic limitations. Further information on EPA's decision can be found in section V.B. below and in the memorandum entitled, "MACT Floor Determination for Existing Stationary Non-Emergency CI RICE Less Than 100 HP and Existing Stationary Emergency CI RICE Located at Major Sources and GACT for Existing Stationary CI RICE Located at Area Sources," which is available from the rulemaking docket.

2. Existing Stationary Non-Emergency CI Engines 100≤HP≤300

EPA is finalizing a CO emission standard for existing stationary non-emergency CI engines greater than or equal to 100 HP and less than or equal to 300 HP located at major sources of 230 ppmvd CO at 15 percent O_2 standard. EPA revised the proposed CO standard for this group of engines based on additional information and data received after the proposal, which led to a reevaluation of the MACT floor for these stationary engines. A discussion of the final MACT floor determination can be found in the memo entitled "MACT Floor and MACT Determination for Existing Stationary Non-Emergency CI RICE Greater Than or Equal to 100 HP Located at Major Sources," which is available from the rulemaking docket. All existing stationary CI engines less than or equal to 300 HP located at area sources, both emergency and non-emergency, are subject to management practice standards under the final rule, as was proposed.

3. Existing Stationary Non-Emergency CI Engines >300 HP

EPA proposed that existing stationary non-emergency CI engines greater than 300 HP meet a 4 ppmvd CO at 15 percent O_2 standard or a 90 percent CO reduction standard. Numerous commenters indicated that EPA's dataset was insufficient and urged EPA to gather more data to obtain a more complete representation of emissions from existing stationary CI engines. Commenters also questioned the emission standard setting approach that EPA used at proposal and claimed that the proposed standards did not take into account emissions variability and may not be achievable. For the final rule EPA has obtained additional test data for existing stationary CI engines and has included this additional data in the MACT floor analysis. EPA is also using an approach that better considers emissions variability, as discussed in V.B. below.

In the final rule, EPA is providing owners and operators the option of meeting either a CO concentration or a CO percent reduction standard. Owners and operators of existing stationary non-emergency CI engines greater than 300 HP and less than or equal to 500 HP located at major and area sources must either reduce CO emissions by at least 70 percent or limit the concentration of CO in the engine exhaust to 49 ppmvd, at 15 percent O_2. Owners and operators of existing stationary non-emergency CI engines greater than 500 HP located at major and area sources must either reduce CO emissions by at least 70 percent or limit the concentration of CO in the engine exhaust to 23 ppmvd, at 15 percent O_2. EPA's review of the data indicate that it is appropriate to base the MACT standard on a reduction level of 70 percent, which takes into account the variability of the emission reduction efficiency of aftertreatment under various operational conditions.

4. Existing Stationary Emergency CI Engines 100≤HP≤500 Located at Major Sources

For existing stationary emergency engines located at major sources, we proposed that these engines be subject to a 40 ppmvd CO at 15 percent O_2 standard. In the final rule, existing stationary emergency CI engines greater than or equal to 100 HP and less than

or equal to 500 HP and located at major sources must meet work practices. These work practices are described in section III.C. of this preamble. EPA believes that work practices are appropriate and justified for this group of stationary engines because the application of measurement methodology is not practicable due to technological and economic limitations. Further information on EPA's decision can be found in the memorandum entitled "MACT Floor Determination for Existing Stationary Non-Emergency CI RICE Less Than 100 HP and Existing Stationary Emergency CI RICE Located at Major Sources and GACT for Existing Stationary CI RICE Located at Area Sources," which is available from the rulemaking docket.

5. Existing Stationary Emergency CI Engines >500 HP Located at Area Sources

For existing stationary emergency engines located at area sources, EPA reevaluated the information available for emergency engines and considered extensive input received from industry and other groups who asserted that the proposed standards were not GACT for emergency engines at area sources. In the final rule, as discussed below in section V.B., all existing stationary emergency CI engines located at area sources must meet management practice standards.

C. Management Practices

EPA proposed management practices for several subcategories of engines located at area sources. EPA explained that the proposed management practices would be expected to ensure that emission control systems are working properly and would help minimize HAP emissions from the engines. EPA proposed specific maintenance practices and asked for comments on the need and appropriateness for those procedures. Based on feedback received during the public comment period, which included information submitted in comment letters and additional information EPA received following the close of the comment period from different industry groups, EPA is finalizing management practices for existing stationary non-emergency CI engines less than or equal to 300 HP located at area sources and all existing emergency stationary CI engines located at area sources.

Existing stationary non-emergency CI engines less than or equal to 300 HP located at area sources are required to change the oil and filter every 1,000 hours of operation or annually, whichever comes first, inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. Existing emergency stationary CI engines located at area sources are required under the final rule to change the oil and filter every 500 hours of operation or annually, whichever comes first, inspect air cleaner every 1000 hours of operation or annually, whichever comes first, and inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. EPA is adding an option for sources to use an oil change analysis program to extend the oil change frequencies specified above. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. If the condemning limits provided below are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil before continuing to use the engine. The condemning limits are as follows:

- Total Base Number is less than 30 percent of the Total Base Number of the oil when new; or
- Viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or
- Percent water content (by volume) is greater than 0.5.

Owners and operators of all engines subject to management practices also have the option to work with State permitting authorities pursuant to EPA's regulations at 40 CFR subpart E for alternative maintenance practices to be used instead of the specific maintenance practices promulgated in this rule. The maintenance practices must be at least as stringent as those specified in the final rule.

The final rule specifies that in situations where an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work or management practice requirements on the schedule required in the final rule, or if performing the work or management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the maintenance activity can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The maintenance should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

D. Startup, Shutdown and Malfunction

EPA proposed formaldehyde and CO emission standards for existing stationary engines at major sources to apply during periods of startup and malfunction. EPA also proposed certain standards for existing stationary engines at area sources that would apply during startup and malfunction. Based on various comments and concerns with the proposed emission standards for periods of startup, EPA has determined that it is not feasible to finalize numerical emission standards that would apply during startup because the application of measurement methodology to this operation is not practicable due to technological and economic limitations, as discussed in detail in section V.D.

As a result, EPA is promulgating operational standards during startup that specify that owners and operators must limit the engine startup time to no more than 30 minutes and must minimize the engine's time spent at idle during startup. Based on information reviewed by EPA, engine startup typically requires no more than 30 minutes. We received comments indicating that there are conditions where it may take more than 30 minutes to startup the engine, for example for cold starts or where the ambient conditions are very cold. However, commenters did not provide enough specificity in their comments, nor did commenters provide data, to determine whether any scenarios were appropriate to allow a longer startup period. Owners and operators of engines at major sources have the option to petition the Administrator pursuant to 40 CFR 63.6(g) for alternative work practices. Any petition must be based on specific factual information indicating the reason the alternative work practice is necessary for that engine and is no less stringent than startup requirements in the rule. An owner or operator of an engine at an area source can work with its State permitting authority pursuant to EPA's regulations at 40 CFR subpart E for approval of an alternative management practice, based on specific factual information indicating the reason that an alternative management practice is necessary for that engine. Such alternative management practice must be demonstrated to be no less

stringent than EPA promulgated standards.

As discussed further below, in section V.D., EPA is not setting separate standards for malfunctions in this rule. Therefore, the standards that apply during normal operation also apply during malfunction. EPA believes that any emissions occurring during a malfunction would be of such a short duration compared to the emissions averaged during overall testing time (three one-hour runs) that the engine would still be able to comply with the emission standard. In addition, EPA does not view malfunction as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be taken into account in setting CAA section 112(d) standards. Further, as is explained in more detail in Section V.D. below, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take into account malfunctions in setting CAA section 112(d) standards.

E. Other

EPA is including an additional requirement in the final rule that will reduce metallic HAP emissions. Owners and operators of existing stationary non-emergency CI engines greater than 300 HP must do one of the following if the engine is not already equipped with a closed crankcase ventilation system: (1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or (2) install an open crankcase filtration emission control system that reduces the crankcase emissions by filtering the exhaust stream to remove oil mist, particulates, and metals. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements.

EPA is including special provisions in the final rule for existing stationary non-emergency CI RICE greater than 300 HP located at area sources in Alaska not accessible by the FAHS. Owners and operators of these engines do not have to meet the CO emission standards specified in Table 2 of this preamble, but must instead meet the management practices that are described for stationary non-emergency CI RICE less than or equal to 300 HP in section III.C. of this preamble.

The final rule specifies that stationary CI engines that are used to startup combustion turbines should meet the same requirements as stationary emergency CI engines.

V. Summary of Responses to Major Comments

A more detailed summary of comments and EPA's responses can be found in the document entitled "Response to Public Comments on Proposed National Emission Standards for Hazardous Air Pollutants for Existing Stationary Reciprocating Internal Combustion Engines Located at Area Sources of Hazardous Air Pollutant Emissions or Have a Site Rating Less Than or Equal to 500 Brake HP Located at Major Sources of Hazardous Air Pollutant Emissions," which is available from the rulemaking docket (*see* **ADDRESSES** section).

A. Applicability

Comment: Numerous commenters expressed concern over EPA's decision to not distinguish between rural and urban engines at area sources in the proposed rule. Several commenters requested that EPA reevaluate its congressional authority to regulate area HAP sources in rural areas. The commenters believed that the proposal is inconsistent with 42 U.S.C. 7412(n)(4)(B) [CAA section 112(n)(4)(B)]. Commenters requested clarification of EPA's rationale to regulate low levels of emissions from engines at oil and gas production facilities outside metropolitan areas, contending that EPA has applied this rule more broadly than the Congressional intent of the CAA, and requested that EPA reevaluate this issue of whether EPA can regulate rural area sources in light of the 42 U.S.C. 7412(n)(4)(B) language.

Commenters stated that EPA has based this rulemaking for area sources on sections of the CAA and its Urban Air Toxics Strategy that are intended to remove threats to public health in urban areas. The commenters do not believe that the remote RICE at area sources in the oil and gas industry threaten public health in urban areas. Several commenters noted that the NESHAP for glycol gas dehydrators (40 CFR part 63, subpart HH) takes into account the location of area sources and does not apply the specific requirements of the rule to rural area sources. The commenters believe that the same approach should be used for the RICE rule, *i.e.*, engines that are not located in or near populated areas should be exempt or subject to an alternative set of requirements so as not to force expensive requirements on remote engines that have no impact on public health.

One commenter on behalf of the agricultural industry expressed that the operational area of these engines has not been studied to evaluate the environmental benefit obtained in congested areas as compared to open agricultural locations. This commenter opined that there should be some measure of variable compliance provided in relation to the area of operation of these engines.

Response: EPA is finalizing its proposal to regulate existing stationary CI engines located at area sources on a nationwide basis. EPA has not made a final determination with regard to existing SI engines at area sources, and will do so in the later rule finalizing regulations for SI engines. EPA believes that the CAA provides the Agency with the authority to regulate area sources nationwide. Section 112(k)(1) of the CAA states that "It is the purpose of this subsection to achieve a substantial reduction in emissions of hazardous air pollutants from area sources and an equivalent reduction in the public health risks associated with such sources including a reduction of not less than 75 per centum in the incidence of cancer attributable to emissions from such sources." Consistent with this expressed purpose of section 112(k) of the CAA to reduce both emissions and risks, CAA section 112(k)(3)(i) requires that EPA list not less than 30 HAP that, as a result of emissions from area sources, present the greatest threat to public health in the largest number of urban areas. Sections 112(c)(3) and (k)(3)(ii) of the CAA require that EPA list area source categories that represent not less than 90 percent of the area source emissions of each of the listed HAP. Section 112(c) of the CAA requires that EPA issue standards for listed categories under CAA section 112(d). These relevant statutory provisions authorize EPA to regulate listed area source engines and not just engines located in urban areas. EPA believes that sections 112(c) and 112(k) of the CAA do not prohibit issuing area source rules of national applicability. EPA also disagrees with the statement that the proposal was inconsistent with section 112(n)(4)(B) of the CAA. The term "associated equipment" was defined for the purposes of subpart ZZZZ in the first RICE MACT rule not to include stationary RICE. EPA has not revisited that issue in this rule and the commenters have not provided sufficient reason to revisit that issue.

EPA does not believe that existing stationary CI engines are more prevalent

in rural areas than in urban areas. Indeed, EPA estimates that only 17 percent of stationary CI area source engines subject to the rule are located in rural areas, using the definitions used in the Urban Air Toxics Strategy. Given the requirement to regulate all engines in the source category in urban areas, we do not believe requiring regulation on a national basis is inappropriate.

The majority of stationary CI engines are used for emergency purposes. EPA has estimated that 80 percent of stationary CI engines are emergency engines and EPA has taken steps in the final rule to reduce the burden on owners and operators of these engines. All emergency CI engines located at area sources of HAP emissions are subject only to management practices under the final rule. EPA has also determined that existing emergency engines located at residential, institutional, and commercial facilities that are area sources of HAP emissions were not included in the original Urban Air Toxics Strategy inventory and therefore are not included in the source category listing. In the final rule, EPA has specified that those engines are not subject to subpart ZZZZ. In addition, existing non-emergency CI engines less than or equal to 300 HP that are located at area sources of HAP emissions are also only subject to management practices. EPA believes that requiring management practices instead of specific emission limitations and/or control efficiency requirements on the majority of existing stationary CI engines at area sources alleviates concerns regarding costly and burdensome requirements for rural sources.

For existing stationary non-emergency CI engines greater than 300 HP, EPA determined that GACT was the use of oxidation catalyst control. The commenters did not provide a reason that GACT would be different for non-emergency stationary CI engines located in rural areas. In determining GACT, EPA can consider factors such as availability and feasibility of control technologies and management practices, as well as costs and economic impacts. These factors are not different for existing stationary non-emergency CI engines in urban versus rural areas. For example, the availability of oxidation catalysts would be the same for urban and rural engines, and if an engine was in a rural location, that would not preclude an owner from being able to install aftertreatment controls. For the final rule, EPA estimated the capital cost of retrofitting an existing stationary non-emergency CI engine to around $7,000 for a 300 HP engine. Annual costs of operating and maintaining the control device are estimated to be approximately $2,000 per year for the same engine. These costs would not be prohibitive for any engines and either rural or urban areas and are expected to be the same no matter the location. Furthermore, the controls that are expected to be used on non-emergency engines above 300 HP will have the co-benefit of PM reductions. PM emissions can travel tens or hundreds of miles from their source, so emissions from diesel engines in rural areas can impact urban populations. There is also no reason to distinguish between the rural and urban area source engines that are subject to management practices. There is nothing limiting owners and operators of existing stationary CI engines located in rural areas from following the management practices specified in the final rule.

In response to requests that agricultural stationary engines should be treated differently from other engines and should be allowed special provisions, EPA is of the understanding that the majority of stationary engines used for agricultural purposes are below 300 HP. Several commenters representing agricultural interests have made the statement to EPA that most of their engines are below 300 HP. As previously discussed in this response, EPA is finalizing management practices for area source engines less than or equal to 300 HP. Therefore, it is not expected that many stationary agricultural engines will be required to put on controls. Agricultural engines less than or equal to 300 HP at rural and urban area sources would be required to follow the management practices specified in the final rule. Management practices will ensure that emissions are reduced and engines are properly operated.

Consistent with the proposal and for the reasons discussed, EPA is finalizing national requirements for existing stationary CI engines without a distinction between urban and non-urban areas.

Comment: Five commenters expressed that EPA's proposal would have a significant impact to the State of Alaska, especially with respect to power generation in their rural communities. They explained that Alaska has unique regional circumstances whereby regulating diesel engine emissions in rural Alaska in the same manner as other engines nationwide could have unintended negative consequences. The commenters were concerned about the extension of section 112(k) of the CAA requirements to rural sources, expressing that the purpose of CAA section 112(k) is to address urban issues. The commenters opined that the scale of HAP emissions in rural areas of Alaska is different and should be addressed in a way that is appropriate to the rural conditions that exist there. The commenters expressed that, historically, EPA has recognized the unique aspects of rural Alaska's diesel distribution system and diesel engine use and has allowed Alaska some flexibility (*e.g.*, under the CI NSPS). The commenters requested that EPA assess and consider rural Alaska's situation and allow for flexibility to address the challenges associated with the proposed rule.

Response: EPA agrees with the commenters that stationary CI area source engines located in remote areas of Alaska have special challenges that should be taken into consideration. As the commenters noted, over 180 rural communities in Alaska that are not accessible by the Federal Aid Highway System rely on stationary diesel engines and fuel for electricity. They are scattered over long distances in remote areas and are not connected to population centers by road or power grid. They are located in the most severe arctic environments in the United States. Transportation of diesel fuel to these areas is dependent on weather and communities typically pay some of the highest prices for fuel in the United States. Stationary engines located in rural areas of Alaska have different fuel storage and use logistics and higher operating and compliance costs. Many of these communities are accessible only by plane. In light of the comments, we believe it is appropriate to treat engines located at area sources in areas of Alaska that are not accessible by the Federal Aid Highway System as a separate subcategory. We re-evaluated GACT for the subcategory of stationary engines located at area sources of HAP that are in an area of Alaska that is not accessible by the Federal Aid Highway System. For these engines, we determined that GACT is the same management practices as those required for non-emergency CI RICE less than or equal to 300 HP located at area sources. For more discussion of this issue, refer to the memo entitled "MACT Floor Determination for Existing Stationary Non-Emergency CI RICE Less Than 100 HP and Existing Stationary Emergency CI RICE Located at Major Sources and GACT for Existing Stationary CI RICE Located at Area Sources."

B. Final Emission Requirements

Comment: Several commenters expressed opposition to EPA's proposal to have emission standards apply to

small engines at major sources. Three commenters said that EPA should not finalize emission limits for engines less than 100 HP. One commenter argued that stationary engines that are less than 100 HP should be exempted from numerical HAP emission standards. In the commenter's opinion, it is not cost effective to install add-on controls on small engines or to purchase a new engine. According to the commenter, the majority of engines in this size range are operated for intermittent household or other infrequent use and emissions are naturally limited, the commenter said, and low emissions do not justify the costs associated with requiring a numerical HAP limit. One commenter does not believe that measurement is economically practicable for a small unit as the cost of testing will likely exceed the value of the engine itself. The commenter urged EPA to exclude small sources from the category.

Response: EPA has reanalyzed its proposed standards based on the information and data presented and EPA concludes that it is not feasible within the context of this rulemaking to prescribe emission limitations for existing stationary CI engines smaller than 100 HP located at major sources, because the measurement of emissions from these engines is not practicable due to technological and economic limitations. In order to measure the emissions from these engines on a ppmvd at 15 percent O_2 basis, the following test methods are required: EPA Method 1 or 1A for selection of sampling ports; EPA Method 3, 3A, or 3B for determining the O_2 concentration; EPA Method 4 for measuring the moisture content, and EPA Method 10 or ASTM D6522–00 (2005) for measuring the CO concentration. These test methods require the sample point to be a certain distance between the engine and the exhaust. Because engines below 100 HP often have exhaust pipes with very small diameters and lengths, stack testing using these methods could require a modification or extension of the exhaust pipe to accomplish the test. The cost to do the testing ranges from approximately $1,000–$5,000 depending on the method used. Generally, 100 HP engines cost around $5,000–$7,000 dollars and 50 HP engines cost approximately $4,000–$5,000, so the cost of performance testing could approach the cost of the engine itself. Given the cost of the testing itself, the physical adjustments necessary to accomplish the test, and the particular circumstances pertaining to stationary engines below 100 HP, we believe that the application of measurement methodology to this class of engines is not practicable due to technological and economic limitations. Therefore, EPA is promulgating work practice standards for these engines. Additional detail regarding this analysis can be found in the memorandum entitled "MACT Floor Determination for Existing Stationary Non-Emergency CI RICE Less Than 100 HP and Existing Stationary Emergency CI RICE Located at Major Sources and GACT for Existing Stationary CI RICE Located at Area Sources."

Comment: One commenter stated that the use of CO as a surrogate for HAP emissions from stationary diesel engines is flawed and does not meet the DC Courts three part test for reasonableness. According to the commenter, the DC Court surrogate three part test requires EPA to demonstrate each of the following: (1) HAP from the source must be "invariantly present" in the surrogate; (2) control technology that reduces the surrogate must "indiscriminately capture" HAP from the source; and (3) control of the surrogate is the only means to control HAP from the source. The commenter pointed out that EPA admitted that CO may not be an adequate surrogate for metallic HAP emissions in the current proposal. The commenter argued that oxidation catalyst is only capable of 30 percent reduction of PM, thus allowing 70 percent of the PM, including metallic and semi-volatile HAP to be emitted to the atmosphere. In addition, the commenter pointed out that technologies that control CO are not the only means by which a source can achieve reductions in HAP emitted from stationary diesel engines. The commenter believes that based on the DC Court's three tests, final standards are not appropriate, and recommended that EPA adopt standards based on PM rather than CO reductions.

Response: EPA believes that CO emissions are an appropriate surrogate for HAP emissions for stationary CI engines. EPA has demonstrated the relationship between CO emissions and HAP emissions in previous rulemakings for stationary engines. EPA does not have any data to support a relationship between PM emissions and HAP emissions for stationary CI engines, nor did the commenter provide any data to support such a relationship for this source category. It is clear that there are methods for reducing PM emissions, like reducing sulfur from fuel, that may not lead to a reduction in HAP. In addition, it is not clear that reductions in PM would reduce emissions of all HAP emitted from stationary engines, particularly emissions of formaldehyde, acetaldehyde, *etc.*, that represent the vast majority of the HAP emissions from this source category. Therefore, for this particular source category, use of PM as a surrogate for HAP is not appropriate. The commenter also did not provide any data from testing of stationary CI engines to show that CO is not a good surrogate for metallic HAP. CO is also a better surrogate for HAP emitted from stationary CI engines than PM because PM is more difficult and expensive to measure than CO for this source category. For semi-volatile HAP, the testing conducted by EPA at Colorado State University showed that an oxidation catalyst reduced PAH emissions by greater than 90 percent for most of the PAH that were tested, and that CO level reductions correlated with level reductions in such HAP.

In addition, as discussed above, EPA is taking an additional action pursuant to its authority under section 112(d)(2)(B) and (C) for further control of metallic HAP. EPA determined that the most effective and achievable method for of controlling metallic HAP emissions from existing stationary CI engines is through the use of crankcase emission control systems. Combustion gases and oil mist that are vented from the engine crankcase are a substantial source of any metallic HAP emissions from stationary CI engines. EPA is promulgating a further standard under section 112(d)(2)(B) and (C) that requires stationary non-emergency diesel engines greater than 300 HP to install either an open or closed crankcase filtration emission control system if the engine is not already equipped with one. The open crankcase filtration emission control system reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals. In the case of the closed system, crankcase emissions are collected and filtered and those that remain in a gaseous state are routed to the intake manifold for burning. We believe this requirement will reduce metallic HAP from the stationary engine emissions.

Comment: Multiple commenters were concerned with how EPA set the MACT floor for the proposed rule. Several commenters said that EPA has not considered variability in setting the MACT floor for the proposed rule. A commenter cited the recent Brick MACT ruling which indicated that "floors may legitimately account for variability [in the best performing sources that are the MACT floor basis] because "each [source] must meet the [specified] standard every day and under all operating conditions." The commenters

stated EPA's data set is not sufficient in covering variability. One commenter noted that the Courts have been critical of EPA's process for setting minimum allowable emission limits. The commenter stated that EPA set the emission limits by averaging the best 12 percent of all performance tests for each subcategory, but did not consider operational variations of the units. The commenter recommended that EPA set emission limits at the emissions level that is actually achieved under the worst reasonably foreseeable circumstances for the best performing 12 percent as allowed by the Courts in the Cement Kiln MACT and Brick Kiln MACT decisions.

Multiple commenters suggested that EPA should consider a scenario under which lower temperatures and reduced catalyst efficiencies may occur due to reduced engine speed or load, resulting in lower temperatures and consider an alternative work practice under section 112(h) of the CAA for the situation. Two commenters noted that the emission standards in the proposed rule apply at all times, but that there is no data or information in the rulemaking docket that supports the proposed limits at low loads or at operating conditions other than high load. The commenters expressed that EPA should provide data and analysis that supports requiring emission limits to be met at all times. Also, for compliance at all times, the commenter asked what averaging times apply.

Response: EPA agrees that emissions variability should be better analyzed and has included a revised approach to variability in the MACT floor analysis. The final emission standards are based on test data collected from stationary engines produced by different engine manufacturers, operating at various loads and other conditions, and located in various types of service and locations. The engines range in size from 160 HP to 3,570 HP. The data includes engines operating at loads from 25–100 percent. To the extent commenters believed further data would have beneficial to EPA, EPA must make its determinations based on the information available to it. EPA asked for further data, and EPA did receive further data following the proposal, which led to changes in the final regulations. For engines operating at reduced speed or loads resulting in a reduced exhaust temperature, EPA believes that numerical emission requirements are still appropriate and there is no justification to only require work practice standards during these situations. We do not believe that the provisions of section 112(h) of the CAA are met (except as discussed elsewhere with regard to periods of start-up, emergency engines, and engines below 100 HP) because testing is not economically and technologically impractical and the emissions can be readily routed through a conveyance for purposes of emission testing. EPA believes that the final emission standards will be achievable at all times covered by the standards and will reflect the numerous engine models and operating scenarios that can be expected from stationary engines.

Regarding the comment asking about the averaging times that apply, EPA has clarified in the final rule that the emission standards are based on the average of three one-hour runs.

Comment: Several commenters expressed concern with the proposed limits for emergency engines at both area and major sources. Numerous commenters stated that EPA should adopt management practices for emergency engines at area sources and not require emission limits from these engines. Commenters stated that emergency engines need special consideration, due to minimal operation, and the commenters said that EPA should apply section 112(h) of the CAA for emergency engines at major sources because of this limited operation. Several commenters recommended that emergency engines be subject to only work practice standards that limit the number of hours allowed for operation during non-emergency events.

Several commenters recommended that EPA require management practices rather than a numerical emission limit for emergency diesel generators greater than 500 HP at area sources. The commenters suggested that such management practices could replace the existing proposed emission standard requirements for emergency CI engines greater than 500 HP. The commenters stated that the proposed rule and related docket indicates that CI emergency diesel engines can achieve a 40 ppmvd CO emission standard for both normal operations and startup or malfunction periods without add-on technology, which the commenters did not believe was correct. The commenters said the proposed rulemaking does not provide any basis for the proposed standards for emergency engines of this size range, and the GACT determination has not been properly established for these engines. In particular, according to the commenters, subsection 1 of section IV.B. of the proposed rule, which is cited in subsection 2 as the basis for the area source standards for large CI engines, does not appear to include any discussion of emission controls for emergency CI engines greater than 500 HP. In the absence of such justification, the commenters state that the MACT floor for these large engines is no controls. The commenter acknowledged that such a no control argument may not be acceptable under the MACT because of the Brick MACT court case, but the commenters stated that there is no such limitation in making GACT determinations. The commenter was concerned that establishing an emission standard for large emergency CI engines would establish requirements for the installation of add-on controls for some, if not most of the sources in that category. EPA needs to conduct a regulatory analysis and assessment of the costs of these controls. The commenter gave an example of the impact of an emission limit and the impact of installing controls on one of his units. The commenter concluded that because of the unit's limited operation, an oxidation catalyst control will have limited, if any, control effectiveness in actual use.

The commenters said that despite EPA's claims that the agency is not requiring performance tests of emergency engines, major sources with existing emergency engines appear to have an implicit testing requirement to demonstrate that they comply with concentration limits. Such testing could significantly increase the time the typical emergency engine would be used in year and impose additional environmental impact and costs. The commenters said EPA needs to resolve the conflict between the preamble and the regulatory language and replace the emission limits for emergency engines with work practices. The commenters raised similar concerns about the apparent requirement for performance testing of emergency RICE due to ambiguous rule language and said it should be clarified to explicitly state that such testing is not required. The commenter said the rule would require not only initial performance testing, but testing every 3 years. Because engine operation for performance testing would likely exceed typical operation for operational testing and maintenance, these testing requirements would result in increased operation of the engine with a corresponding significant increase in operating costs and emissions of other pollutants such as NO_X. The commenters said emergency engines are used only during emergencies, other than short (less than one-half hour) weekly tests to assure the engines will perform. According to the commenter, performance tests (initial or

every 3 years) consisting of three 1-hour runs typically cost about $10,000 each and are not justified for limited use engines, the tests alone would add substantially to the fuel use of these engines are result in additional and unnecessary emissions and work practice standards under section 112(h) are more appropriate due to "technological and economic limitations."

Response: EPA reviewed the information submitted by the commenters and determined that it would be appropriate to require management practices for all emergency stationary CI engines at area sources. Because these engines are typically used only a few number of hours per year, the costs of emission control and the costs of emission testing are not warranted when compared to the emission reductions that would be achieved. The proposed numeric emission levels are not GACT for emergency engines at area sources. Such engines rarely if ever use the type of emission controls that might have been necessary for many engines to meet the numeric standard, and such engines are rarely if ever subjected to emissions testing. Therefore, EPA determined that GACT for all stationary emergency engines at area sources is the use of management practices.

EPA also analyzed the types of engines that were included in the area source category listing for stationary RICE. As a result of this analysis, EPA determined that emissions from existing stationary emergency engines located at residential, commercial, and institutional facilities that are area sources of HAP were not included in the 1990 baseline emissions inventory that was used as the basis for the listing of source categories needed to ensure that 90 percent of area source emissions are regulated. Existing stationary emergency engines located at residential, commercial, and institutional facilities that are area sources are therefore not subject to this regulation.

For stationary emergency engines at major sources, EPA determined that it is not feasible to prescribe or enforce an emission standard because the application of measurement methodology to this class of engines is impracticable due to technological and economic limitations. A more detailed discussion of this determination can be found in the memorandum entitled "MACT Floor Determination for Existing Stationary Non-Emergency CI RICE Less Than 100 HP and Existing Stationary Emergency CI RICE Located at Major Sources and GACT for Existing Stationary CI RICE Located at Area Sources." EPA determined that it is impracticable to test stationary CI emergency engines using the test procedures specified in subpart ZZZZ because using these procedures would increase the required number of hours of operation of the engine beyond the routinely scheduled reliability testing and maintenance operation, thereby increasing emissions. While emergency engines have periods of operation for scheduled maintenance and reliability testing, those periods are usually several hours shorter than the number of hours that would be required to run the necessary emissions tests under subpart ZZZZ. CARB conducted a survey of stationary emergency diesel engines in 2002 [2] to determine the average number of hours that stationary emergency diesel engines operate. The average hours of operation for maintenance and testing were 22 hours per year, which is less than two hours per month. For the engines that CARB surveyed, 86 percent operated less than 30 hours/year for testing and maintenance. Thirty percent operated less than 10 hours/year. National Fire Protection Association (NFPA) codes require that stationary diesel engines that are used for emergency purposes are run 30 minutes per week (27 hours per year) for maintenance and testing purposes. It is impracticable to test emergency stationary engines as a result of emergency operation because emergencies are unplanned events and implementation of the test procedures specified in subpart ZZZZ require advance planning before tests are conducted. In an emergency, the owner/operator does not have the advance planning time necessary to implement subpart ZZZZ. It is also impracticable to test stationary CI emergency engines at major sources because of the large population of these engines. EPA estimates that there are over 200,000 existing stationary CI engines from 100–500 HP at major sources that are subject to this rulemaking. There are only approximately 300–400 testing firms and these stationary engines are not the only sources that are required to be tested, so if testing were required for these engines, it would take many years to test all of these engines. The cost for testing all of these engines would also be approximately $200 million, which would be unreasonable.

EPA expects that these changes from the proposed rule address the concerns expressed by the commenters about the requirements for stationary emergency CI engines. Regarding the comments pertaining to performance testing for emergency engines, EPA did not intend for the rule to require performance testing for emergency engines. The final rule does not contain any performance testing requirements for emergency engines.

Comment: One commenter recommended that the standard require CDPF or a combination of oxidation catalysts and CDPF for new or existing non-emergency diesel RICE. The commenter stated that EPA's proposal calls for oxidation catalysts on non-emergency CI engines, which EPA reports will result in a 90 percent reduction in CO and 30 percent reduction in PM, whereas CDPF would result in greater reductions in PM (90 percent reductions or greater).

Another commenter reported that it had conducted risk assessment evaluations for diesel particulate emissions from non-emergency diesel engines and found that the diesel particulate emissions from non-emergency diesel engines and found that the diesel particulate emissions often create a significant cancer risk even when there is a 30 percent PM reduction. The commenter recommended that EPA base standards on CDPF or a combination of oxidation catalyst and CDPF, for existing and new non-emergency diesel engines.

Response: The standards that EPA proposed and that EPA is finalizing do not require a particular control technology. For the proposed rule, EPA's beyond-the-floor analysis resulted in standards that were based on the use of oxidation catalyst control for stationary non-emergency diesel engines above 300 HP; EPA has made the same determination for the beyond-the-floor standards in the final rule. EPA determined that the MACT standards should be based on oxidation catalyst rather than CDPF because we do not have any data that shows that CDPFs get greater reductions of HAP than oxidation catalysts on stationary engines, and CDPFs are approximately four times as costly as oxidation catalysts.[3] EPA also has concerns regarding the technical feasibility of CDPFs for existing stationary diesel engines. Many existing diesel engines are not electronically controlled, and PM emissions from older engines are often too high for efficient operation of

[2] *California Air Resources Board Staff Report:* Initial Statement of Reasons for Proposed Rulemaking. Airborne Toxic Control Measure for Stationary Compression Ignition Engines. Stationary Source Division, Emissions Assessment Branch. September 2003.

[3] *California Air Resources Board Staff Report:* Initial Statement of Reasons for Proposed Rulemaking. Airborne Toxic Control Measure for Stationary Compression Ignition Engines. Stationary Source Division, Emissions Assessment Branch. September 2003.

a CDPF. Further, engine exhaust temperatures are often not high enough for regeneration of the CDPF filter substrate. EPA notes that owners and operators are free to choose whichever control technology, which could be oxidation catalyst or CDPF, as long as they meet the final standards. EPA is not addressing new diesel engines in this rulemaking.

Comment: A few commenters were concerned about requirements that might apply to engines that startup turbines. Four commenters suggested that RICE used to startup combustion turbines be exempt from the proposed rule, or deemed to fall under the "emergency" definition in 40 CFR § 63.6675. One commenter explained that turbine RICE only run for a few minutes to get the unit started and the total fuel consumption is not significant. One commenter was concerned that the short run-time during each operation may not be long enough to get the filter up to its design temperature for achievement of its removal efficiency (and note that EPA discusses it in the preamble) or that a filter may require additional run time for regeneration. The commenter further noted that the additional run-time required by the 3 year testing requirement could outstrip the run-time needed to support these combustion turbine peaking unit starting devices just for compliance with the RICE rule. The commenter noted that increased consumption of fuel for rule compliance would be wasting the natural resource and adding emissions for no measurable reduction being gained by the rule. Two commenters noted that every major power plant in the United States is required to have black start capability, which typically involves a small combustion turbine equipped with a diesel engine used for startup of the turbine. According to the commenter, the diesel starting engine, rated less than 500 HP, generally operates less than 10 minutes per combustion turbine start. The commenter indicated that the majority of black start units only operate during emergencies or unusually high demand days, and that a review of the commenter's company's operating data determined that seven black start units in the system averaged 32 starts per year (which equates to less than 6 hours of operation per year, although some limited additional operation may occur as a result of routine maintenance and readiness testing).

Response: In the final rule EPA has required that stationary engines used to startup combustion turbines meet work practice standards. EPA finds that the short time of operation for these engines (10–15 minutes per start) makes application of measurement methodology for these engines using the required procedures, which require continuous hours of operation, impracticable. Requiring numerical emission standards for these engines would actually require substantially longer operation than would occur normally in use, leading to greater emissions and greater costs. EPA also agrees with the commenters that it would not be appropriate to set emission limits that are based on the use of aftertreatment control for the subcategory of stationary CI engines that are used to startup combustion turbines. Oxidation catalyst control would not be effective for these engines due to their short time of operation (10–15 minutes per start).

C. Management Practices

Comment: Several commenters did not agree with the specific management practices that EPA has proposed in the rule for area sources or recommended different maintenance practices. According to the commenters, the maintenance frequency in the proposed rule exceeds current practices or is not supported in the proposed rule. Several commenters agreed that management practices are appropriate for the proper operation of the engines and is a reasonable means to reduce HAP emissions, however, did not agree with the specific maintenance practices proposed by EPA. Numerous commenters recommended that EPA allow owners/operators to follow engine manufacturers' recommended practices or the owners/operators own site-specific maintenance plan.

One commenter pointed out that operators have a direct interest in maintaining engine oil, hoses, and belts, so the engine runs reliably, but the appropriate frequency for these maintenance practices are specific to engine design and are not "one size fits all." Ten commenters recommended that EPA revise fixed maintenance (one-size-fits-all) requirements to maintenance plans. The commenters stated that, while fixed maintenance intervals work well for new mass produced engines similar to those in automobiles, they are inappropriate for the wide variety of existing engines used in the oil and gas, agriculture, and power generation industries across the nation. The commenters pointed out that EPA allows the use of operator-defined maintenance plans that are "consistent with good air pollution control practice for minimizing emissions" to be used in other portions of this same rule, and asserted that EPA should allow the use of operator-defined maintenance plans to greatly reduce cost and allow operators to optimize maintenance for each type of engine.

One of these commenters added that current industry engine maintenance programs are driven by tried-and-true practices and since these practices effectively keep the engines running, they allow the products of the members of the commenter's organization to go to market. The commenter stated that additional, burdensome, frequent, and time-consuming maintenance requirements will cause the members of the commenter's organization to more-frequently shut down engines and thus shut down production.

Two commenters said that if EPA keeps the management practices as proposed, the frequencies associated with conducting engine maintenance should be revised to be commensurate with today's practices. The commenter believes the maintenance practices, as proposed, are significantly burdensome and lack basis. According to the commenters, EPA should replace the maintenance hour intervals with company recommended performance-based maintenance practices to be documented in an operator-defined maintenance plan consistent with requirements in 40 CFR part 60, subpart JJJJ.

One commenter stated that most of the engine manufacturers for the engines in the oil and gas industry recommend oil changes on a monthly schedule. The commenter also indicated that it is common practice to periodically sample and test the engine oil to see if the oil properties are sufficient to extend this time period between oil changes. According to the commenter, this testing has shown in many cases that the oil change interval can be extended without any detrimental effects on the engine, which allows industry to maximize efficiencies, minimize oil usage, reduce waste, and streamline operations with no negative impacts to the engine or emissions.

One commenter expressed that inspection of hoses and belts has no impact on HAP emissions. The commenter expressed that, generally, it agreed that performing maintenance on engines will help to reduce HAP emissions, but that while inspecting belts and hoses is an important part of general engine maintenance (and most sources likely conduct regular inspections of their engines), such inspections have no effect on emissions and should be removed from the proposed rule.

Response: EPA proposed to require specific management practices for certain engines, primarily for smaller existing stationary engines at area sources where EPA thought that add-on controls were not GACT. EPA indicated at proposal that the management practices specified in the proposal reflected GACT and that such practices would provide a reasonable level of control, while at the same time ensuring that the burden on particularly small businesses and individual owners and operators would be minimized. EPA asked for comment on the proposed management practices and received comments on the proposal from industry.

EPA agrees with the commenters that it is difficult to adopt a set of management practices that are appropriate for all types of stationary engines. Regardless, EPA must promulgate emission standards pursuant to section 112(d)(5) for all engines at area sources covered by the final rule. EPA still believes that a management practice approach reflects GACT for emergency engines and smaller engines at area sources. These management practices represent what is generally available among such engines to reduce HAP, and the practices will ensure that emissions are minimized and engines are properly operated. EPA does not agree with the commenters that it would be appropriate to simply specify that owners and operators follow the manufacturer's recommended maintenance practices for the engine. EPA cannot delegate to manufacturers the final decision regarding the proper management practices required by section 112(d). To address the comments that there may be special and unique operating situations where the management practices in the rule may not be appropriate, for example engines using a synthetic lubricant, EPA notes that owners/operators may work with State permitting authorities pursuant to 40 CFR subpart E ("Approval of State Programs and Delegation of Federal Authorities") for approval of alternative management practices for their engines. Subpart E implements section 112(l) of the CAA, which authorizes EPA to approve alternative State/local/Tribal HAP standards or programs when such requirements are demonstrated to be no less stringent than EPA promulgated standards.

The management practices EPA proposed for stationary engines greater than 50 HP included changing the oil and filter every 500 hours, replacing the spark plugs every 1,000 hours, and inspecting all hoses and belts every 500 hours and replacing as necessary. For engines less than 50 HP, EPA proposed to require that these engines change the oil and filter every 200 hours, replace spark plugs every 500 hours, and inspect all hoses and belts every 500 hours and replace as necessary.

EPA agrees that there is a wide range of recommended maintenance procedures, but EPA must promulgate specific requirements pursuant to section 112(d) for this source category. Based on the different suggested maintenance recommendations EPA has reviewed, maintenance requirements appear to vary depending on whether the engine is used for standby, intermittent, or continuous operation. Maintenance is also dependent on the engine application, design, and model. Taking into consideration the information received from commenters on the proposed maintenance practices for oil and filter changes and carefully reviewing engine manufacturer recommended maintenance procedures, EPA has determined that for stationary non-emergency engines below 300 HP, GACT will require the oil and filter to be changed every 1,000 hours of operation or annually, whichever comes first, which reflects the management practices that are generally available. For stationary emergency engines, the final rule requires the oil and filter to be changed every 500 hours of operation or annually, whichever comes first. EPA notes that in the final rule it has clarified that spark plug changes are not required for stationary diesel engines since diesel engines do not use spark plugs. EPA also determined that it would be appropriate to include the option to use an oil analysis program in the final rule.

EPA does not agree with the comments that inspecting belts and hoses has no impact on emissions. Ensuring that the engine is properly operated and maintained will help minimize the HAP emissions from the engine. Properly maintained belts and hoses allow the engine to operate at maximum efficiency. Hoses are generally used to move coolant through the engine to prevent the engine from overheating. Overheating of the engine can cause a malfunction in the combustion process, and may also burn the engine oil in the combustion chamber. Both of these conditions may increase pollutant emissions from the engine. Belts are commonly used for electrical generation and engine timing, and if worn or broken can cause damage to the engine and increase emissions. Therefore, EPA has required management practices that reflect GACT and that, in EPA's view, will ensure the proper operation and maintenance of the engine.

D. Startup, Shutdown and Malfunction

Comment: Several commenters expressed serious concern over the proposed emission standards for periods of startup, shutdown, and malfunction (SSM). The commenters state that the U.S. Court of Appeals for the District Columbia Circuit vacated the SSM exemption in 40 CFR part 63, subpart A on December 19, 2008, and the decision requires the Agency to implement standards that apply at all times, including during SSM periods. Numerous commenters thought the quick response to the December 2008 Court decision on the SSM issue is premature and recommended that EPA wait for a final decision before incorporate elements from this case. Numerous commenters are of the opinion that EPA has not provided a technical basis for its establishment of SSM limits and that any SSM limits should be replaced with work practice standards and disagreed with the decision to include limits for SSM periods. In addition, several commenters said that emissions during SSM events cannot be measured and therefore cannot be confirmed and limits are not enforceable. One commenter recommended that EPA require a SSM plan similar to the SSM plan currently required under 40 CFR part 63, subpart ZZZZ. The commenter also pointed out that 40 CFR 63.6650(b) in the existing rule requires operators to operate and maintain their equipment in a manner consistent with good air pollution control practices at all times, including periods of SSM. The commenter believed that this requirement in conjunction with a SSM plan will achieve the same goals as the proposed rules in a much more cost effective and logical manner.

Many commenters recommended that EPA consider other alternatives to implement during SSM periods, such as possibly requiring work practice standards, which the commenters believe is the most reasonable approach and is justified under the CAA. Commenters believed that work practice standards that minimize the emissions during SSM periods is the most practical method of keeping HAP emissions from engines as low as possible.

Several commenters said that there is no method to determine compliance during SSM periods. The commenters said that it will be difficult or impossible to design a test program to describe emissions during SSM events, *e.g.*, the commenter is not sure how a

malfunction would be defined considering the unexpected and anomalous nature of the event. Therefore, emissions during these periods cannot be confirmed, the commenters said. Similarly, commenters believed that it is not reasonable to set numerical limits during startup because there are no available or repeatable test methods or procedures for measuring emissions during startup or malfunction, plus there is no prescribed definition of what constitutes startup of an engine, which can vary significantly for a number of reasons such as engine and catalyst type, fuel, climatic conditions, application and load.

One commenter said that there are no viable measurement methods available to measure CO, formaldehyde or VOC during transient operation and a review conducted by the commenter of Table 4 in the proposed rule shows the inconsistencies related to transient measurement acceptability with respect to stack gas moisture and flow rate, delays in the actual response of analyzers, issues in obtaining an accurate measurement during a transient test due to an axial diffusion function in long gaseous emissions sample lines, and field gaseous emission measurements require stack traverse as well for the emissions under measurement, per EPA Methods 7, 10, 25, *etc.*, which eliminates the possibility of getting an accurate measurement during transient events such as a startup.

One commenter claimed that issuance of numerical limits for SSM based on the emissions of the "best controlled sources prior to full warm up of the catalytic control" fails to consider emissions during malfunction of the engines themselves. The commenter asserts that while EPA appropriately determined that during a control device malfunction, the floor and standard cannot be set assuming operation of the control device, EPA errs in limiting its analysis solely to operation of the controls since emissions can increase as a result of engine malfunctions as well. The commenter noted that its experience is consistent with EPA's statements that emissions during an engine malfunction may increase due to the effects on exhaust temperatures and composition. The commenter concluded that emission limits would need to be based on the emissions level from the best performing sources without control while the engine is malfunctioning. One commenter added that it does not make sense to set any numerical standards during a malfunction of an engine because inherent in the concept of a malfunction is that emissions will be malfunctioning as well. It is also not logical to apply the concept of "best performing" malfunctioning engine, the commenter said. For these reasons, it is unreasonable for EPA to promulgate numerical emission limits for periods of malfunction, in the commenter's opinion. Emission testing for malfunctions would be near impossible to conduct given the sporadic and unpredictable nature of the events, the commenter said. The commenter said that the nature of malfunctions means it is not feasible to predict or simulate emissions that occur during periods of malfunctions. The commenter asserted that with respect to engines, it is not technologically or economically feasible to apply measurement methodology for the emissions during SSM periods and further, that it is unreasonable for the Agency in the face of the lack of accurate emission measurements to simply set the standard at the level for normal operations (*e.g.*, for sources not using a control device). The commenter stated that this situation is precisely the circumstance in which Congress envisioned that a work practice standard would be established, and urged EPA to adopt a work practice standard applicable to malfunction and startup periods for engines consistent with section 112(h) of the CAA and not to apply the numerical limits for normal operations.

One commenter stated that EPA solicited comment on the level of specificity needed to define the periods of startup and malfunction. The commenter believes the responses differ based on whether the event is a startup or malfunction. The commenter noted that startup of an engine begins with the start of fuel flow to the engine and ends when the engine has achieved normal operating temperature and air to fuel flows as indicated by the manufacturers' specifications, and while the initiation of a startup is predictable, its conclusion is not time-determined, but operationally-determined. The commenter noted where a catalyst is used to control emissions; startup does not end until the required catalyst bed temperature has been achieved, however, this may happen before the engine air and fuel flows are normal and thus catalyst bed temperature is not the exclusive criterion that defines the end of the startup period. The commenter noted that the start of the malfunction should be defined as when the normal operation emission limit is exceeded and the end of the malfunction should be set as when the normal operation emission limit is restored or the engine is shutdown. The commenter noted that malfunctions often require shutdown to address, but such shutdowns can be delayed because immediate engine shutdown would cause other upsets. Therefore, the commenter believes it would not be reasonable to set any specific time limits on either startup or malfunction periods, because their duration can be a function of operational need. Similarly, one commenter disagreed that it would be appropriate to set a specific limit on the time allowed for startup because not all engines experience the same type of startup and malfunction. The length of startup will depend on many factors including engine type, size, fuel type and duty cycle, plus the frequency of required startups will also vary greatly among engines because some engines are only used for intermittent operation.

Some commenters thought that limiting the engine startup time is a reasonable method to limit emissions. The commenter added that the most effective way to control emissions during startup for engines with catalysts is to limit the amount of time it takes to warm up the exhaust to initialize the catalyzation process and startup time can be easily monitored. The commenter added that the time to be monitored at startup be defined as from the initial engine in-cylinder combustion, corresponding with continuous operation, up to the point that a defined catalyst inlet temperature is reached. The commenter also recommended that owners/operators be able to request additional startup time if necessary in special circumstances, *e.g.*, in extremely cold climates or where sufficient load cannot be reached within 30 minutes. The commenters recommended a limit of one hour for startup and 30 minutes for shutdown. The rule should not include a time limit for malfunctions, as the length of time during which an engine will be out of compliance would depend on the type of malfunction, the commenters said. The commenters suggested that each affected source would be required to prepare a SSM plan, which would have to address appropriate actions and time limits for malfunctions. The commenter suggested that for engine startups, the work practice should require loading the engine to normal operating load as soon as practicable so that the catalytic controls are within operating range as soon as practicable

The commenters also objected to EPA's proposed second option. The commenter said the data are apparently derived from the best controlled engines not using catalytic controls. The commenter said that emissions data

from steady-state operation of uncontrolled engines does not account for the cooler engine and fuel temperature conditions during startup. Nor does the second option properly account for malfunctions.

One commenter proposed that EPA treat SSM emissions as de minimis, using the DC Circuit rationale in Alabama Power Co. v. Costle. The commenter noted that catalyst systems do not perform at low temperatures, and the SSM periods vary in duration and intensity, which can significantly impact actual emissions profiles. The commenter provided examples of why an assumption that SSM emissions are identical to normal stable operations emissions is erroneous and a gross over-simplification of unit operations.

Response: EPA received extensive comments on the proposed requirements applicable to existing stationary engines during SSM. Consistent with the recent Court decision that vacated the exemption in 40 CFR 63.6(f)(1) and (h)(1) for SSM (*Sierra Club* v. *EPA,* 551 F.3d 1019), EPA has established standards in this rule that apply at all times. EPA disagrees with those comments suggesting that EPA was premature in proposing standards during periods of startup, shutdown and malfunction. The United States Court of Appeals for the District of Columbia Circuit issued its opinion vacating the SSM exemption in December 2008, and we appropriately accounted for that decision in proposing the rule in February 2009. EPA does not believe it is appropriate to promulgate final rules that are inconsistent with the decision of the DC Circuit.

EPA has determined that the emissions from stationary CI engines during startup are significantly different than the emissions during normal operation. During startup, incomplete combustion of the diesel fuel causes variations in the pollutant concentrations and fluctuations in the flow rate of the exhaust gas. Incomplete combustion is due to cold areas of the cylinder walls that cause the temperature to be too low for efficient combustion. As the engine continues to operate, these cold regions begin to heat up and allow for more complete combustion of the diesel fuel and stabilization of the exhaust flow rate and pollutant concentrations. In addition, the engine experiences extreme transient conditions during startup, including variations in speed and load, poor atomization of the fuel injection, which leads to variable engine and engine exhaust temperatures, variable exhaust gas flow rates, and variable diluent pollutant concentration. Note for example the brief time spent at different load conditions as shown in Figure 1 of the attachment to EMA's letter dated February 17, 2009 (EPA–HQ–OAR–2008–0708–0019), which illustrates the transient nature of the engine startup phase. Other factors that cause emissions to be higher during startup, including for engines that are not equipped with oxidation catalyst, are a higher propensity for engine misfire and poorer atomization of the fuel spray during startup. After-treatment technologies like oxidation catalysts and CDPFs must also reach a threshold temperature in order to reduce emissions effectively. In the February 17, 2009, EMA letter, EMA provided various graphs illustrating sample engine startup profiles and graphs demonstrating the effect of engine exhaust temperature on catalyst efficiency. Figure 6 of the attachment to EMA's letter (EPA–HQ–OAR–2008–0708–0019.1) shows how the CO efficiency is a function of the catalyst inlet temperature.

EPA has evaluated the criteria in section 112(h) and carefully considered and reviewed the comments on this issue. EPA has determined that it is not feasible to prescribe a numerical emission standard for stationary CI engines during periods of startup because the application of measurement methodology to these engines is not practicable due to the technological and economic limitations described below.

EPA test methods (*e.g.,* 40 CFR part 60, appendix A, Methods 2, 3A, 4, and 10) do not respond adequately to the relatively short term and highly variable exhaust gas characteristics occurring during these periods. The innate and substantial changes in the engine operations during startup operations create rapid variations in exhaust gas flow rate as well as changes in both pollutant and diluent gas concentrations. Correlating the exhaust gas flow rates and the gas components concentration data for each fraction of time over the entire period of a startup operation is necessary to apportion the values appropriately and to determine representative average emissions concentrations or total mass emissions rate.

Measuring flow and concentration data in the types of rapidly changing exhaust gas conditions characteristic of stationary CI engines is unachievable with current technologies applicable to stack emissions testing. For example, application of Method 2 to measure stack flow rate requires collecting data for velocity pressure and stack temperature at each of 12 traverse points and a corresponding stack moisture and oxygen concentration (for molecular weight determination). This traverse operation requires about 30 minutes to complete to produce a single value for the test period, which is approximately the same amount of time as the engine startup period. Clearly a single flow rate value would not sufficiently represent the variable flow conditions nor allow appropriate apportioning of the pollutant concentration measurements over that same period for calculating a representative average emissions value. Even if the start-up period is longer than 30 minutes, the stack flow rate test period could not be short enough to represent the short term (*e.g.,* minute-by-minute) result necessary for representative emissions calculations. These findings lead us to conclude that correlating the flow and concentration data as necessary to determine appropriate proportional contributions to the emissions rates or concentrations in calculating representative emissions over these short highly variable conditions with currently available field testing procedures is problematic for stationary CI engines. In addition, even were it technically feasible to measure emissions during startups for stationary CI engines, the cost of doing so for every startup at every covered engine would impose a substantial economic burden. There are approximately 936,000 existing stationary CI engines that are subject to this rule; the cost for testing every one of these engines during engine startup could be more than $1 billion.

EPA is therefore finalizing an operational standard in lieu of a numerical emission limit during periods of startup in accordance with section 112(h) of the CAA. EPA is limited to the information before it, which, of course, includes any information provided by the commenters. *See* 112(d)(3)(A). In this case, EPA carefully analyzed all of the information before it, including that provided by commenters, and determined that this standard complies with the requirements of sections 112(d) and 112(h). The final rule requires that owners and operators of stationary engines limit the startup time to 30 minutes or less. Engine startup is defined as the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation, including the catalyst. EPA is also including a requirement in the final rule to

minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the otherwise applicable emission standards apply. As with any work practice, CAA section 112(h)(3) and EPA's implementing regulations at 40 CFR 63.6(g) provide that major sources can petition the Administrator for approval of an alternative work practice, which must be at least as stringent as what is required in the regulation.

Regarding shutdown, EPA determined that it was not necessary to establish different standards that would be applicable during shutdown for stationary CI engines. The commenters did not provide any information that shows emissions would be higher during shutdown than during normal operation. In addition, commenters are incorrect that compliance with the standards must be instantaneous. Compliance with these emission standards has always been based on the results of testing that is conducted over a three-hour period; EPA has made this more explicit in this rule. Since the shutdown period for stationary CI engines is typically only a matter of minutes, it is believed that even if a shutdown occurred during the performance test, the engine would still be able to comply with the emission limitation. In a letter dated February 17, 2009 (EPA–HQ–OAR–2008–0708–0019), EMA indicates that HAP emissions will be sufficiently controlled during periods of shutdown. EMA stated in its letter that according to manufacturers, emissions control equipment would most likely continue to reduce emissions as designed throughout the shutdown period. According to EMA, this is because engine emissions control systems and equipment are, during the start of an engine shutdown, at high enough temperatures to control HAP emissions and will continue to be sufficiently high until the engine shuts down. This trend is illustrated in the attachment to EMA's February 17, 2009, letter to EPA, where EMA provided two graphs with sample engine shutdown profiles. Figure 2 of the attachment to EMA's letter (EPA–HQ–OAR–2008–0708–0019.1) shows catalyst temperatures versus minutes during engine shutdown and illustrates stable catalyst temperatures.

In establishing the standards in this rule, EPA has taken into account startup periods and, for the reasons explained above, has established different standards for those periods. With respect to malfunctions, EPA proposed two options for subcategories where the proposed emission standard was based on the use of catalytic controls. The first proposed option was to have the same standards apply during normal operation and malfunctions. The second proposed option was that standards during malfunctions be based on emissions expected from the best controlled sources prior to the full warm-up of the catalytic control. For subcategories where the proposed emission standard was not based on the use of catalytic controls, we proposed the same emission limitations apply during malfunctions and periods of normal operations. EPA is finalizing the first option described above, which is that the same standards apply during normal operation and malfunctions. In the proposed rule, EPA expressed the view that there are different modes of operation for any stationary source, and that these modes generally include startup, normal operations, shutdown, and malfunctions. However, after considering the issue of malfunctions more carefully, EPA believes that malfunctions are distinguishable from startup, shutdown and normal operations.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 63.2). EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. For example, we note that Section 112 uses the concept of "best performing" sources in defining MACT, the level of stringency that major source standards must meet. One commenter expressed the view that it is not logical to apply the concept of "best performing" to a source that is malfunctioning. Indeed, the goal of best performing sources is to operate in such a way as to avoid malfunctions of their units. Similarly, although standards for area sources are not required to be set based on "best performers," we believe that what is "generally available" should not be based on periods in which there is a "failure to operate."

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 112(d) standards for stationary CI engines. As noted above, by definition, malfunctions are sudden and unexpected events and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources. Moreover, malfunctions can vary in frequency, degree, and duration, further complicating standard setting.

Finally, EPA believes that malfunctions will not cause stationary CI engines to violate the standard that applies during normal operations. Stationary CI engines would in most cases shut down immediately or with very little delay in the event of a malfunction. Because the standard is expressed as the average of three one-hour runs, or a work or management practice, any emissions that occur prior to engine shutdown should not affect a source's ability to comply with the standard. Commenters' concerns regarding compliance certifications should not be a concern for this same reason. This approach will also encourage shutdowns as soon as practicable when a malfunction that affects emissions occurs. In the unlikely event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction).

EPA does not agree with the commenter who said that EPA should treat SSM emissions as de minimis. It is doubtful whether a de minimis exemption is even possible under section 112(d) of the Act in these circumstances, *see National Lime Ass'n* v. *EPA*, 233 F. 3d 625, 640 (DC Cir, 2000), but in any case the commenter provides no specific information to justify EPA making such a de minimis finding in this instance. Given the very narrow and specific circumstances delineated by the court in *Alabama Power* v. *Costle*, 636 F.2d 323 (DC Cir. 1979) for making such a finding, and the lack of specific information from the commenter that these circumstances exist in this instance, we do not make a *de minimis* finding.

E. Emergency Engines

Comment: Several commenters stated that EPA's proposed definition of emergency is not clear as to whether it includes emergency engines that operate in emergency demand response (DR) programs. The commenter believed that the record on 40 CFR part 60, subpart IIII, from which the proposed rule definition was drawn, clearly indicates that the 40 CFR part 60, subpart IIII definition was meant to address peak shaving, not emergency engines participating in emergency DR programs. Several commenters requested that EPA modify the proposed definition of emergency engines to enable engines to maintain their status as emergency engines, even though the engines that are used in DR programs are part of a financial agreement and based on the current definition would not be considered emergency engines. Two commenters stated that emergency DR programs should not be confused with economic DR programs (*e.g.*, peak shaving). Emergency DR programs are initiated by the transmission system operators when the threat of power outages is imminent and are critical to maintaining available power during periods of extreme load on the electric power infrastructure, according to the commenters. The events are rare and unplanned, out of the control of emergency engine owners/operators, and no power is supplied to the grid, but used at the individual facility, the commenter said. The commenter said that emergency DR events during the year are typically limited to no longer than 2 to 6 hours per event, with the number of events per year capped by the regional power pool. The commenter believed that, by establishing a subcategory for generators that serve facilities participating in a DR program and that only operate 200 hrs/yr, including any hours operated for maintenance purposes, EPA could require maintenance practices, and remove any disincentive that may be created over the increased administrative burden and potential post-combustion control retrofit costs if their emergency stationary RICE would be required to be re-characterized as "non-emergency" in order to participate in DR programs. The commenter suggested that a 100 hour operating limit could also be considered as an alternative. Three commenters (stated that they receive many benefits from their participation in the local DR program, and that they use emergency DR events and tests events to replace some of the Joint Commission on Accreditation of Healthcare Organizations' mandated hospital generator tests. According to the commenters the costs that they would have to absorb to meet the proposed emission limits would be prohibitive and that to require facilities to meet rigid emission limits with very little reduction in emissions is not encouraged. Emergency engines are used throughout the U.S. and provide vital safety requirements at hospitals and healthcare institutions, the commenters said. Commenters stated that emergency engines participating in emergency DR programs provide a critical service in stabilizing the electric grid on the rare occasions when the grid is about to fail. Many States endorse the use of emergency engines participating in emergency DR programs, according to commenter 82. Two commenters cited various DR programs in the New England area that existing engines participate in. A commenter provided detailed discussion of several emergency DR programs across the country, including States in New England, the Mid Atlantic and Midwest, and the South, that are supportive of using emergency engines as part of their emergency DR programs, and that accommodate operation of these engines through various definitions of emergency, or through permitting. The commenter concluded that it is very important that EPA not adopt rules that conflict with how much of the U.S. handles emergency DR.

Response: EPA agrees that it would be appropriate to allow emergency engines to operate as part of emergency demand response programs for a limited number of hours of operation per year in situations where grid failure and a blackout are imminent. In the final rule, EPA has revised the requirements for emergency engines to reflect this.

F. Emissions Data

Comment: Multiple commenters believe that the emissions data for engines is not adequate to conduct an appropriate MACT floor analysis. EPA should collect additional data and redo the MACT floor analysis, according to numerous commenters. The commenters also stated that EPA did not consider emissions variability in setting the MACT floor.

Commenters stated that the MACT floors should not be based on data using single measurements, when three measurements are a standard requirement for demonstrating compliance. In the absence of multiple measurements, outliers and erroneous errors cannot be caught, according to the commenters.

The commenters said that EPA should use data from units of similar size to set standards for sources of the same size, *e.g.*, emissions from a large engine should not be used to set standards for a 100 HP engine unless EPA can demonstrate that such an assumption is justified. The commenters are concerned that the data EPA has used for the MACT floor analysis is not representative of the current population of engines.

Commenters criticized the applicability and use of the RICE emissions database as representative of the engines being regulated. One commenter noted that the 40 ppmvd numerical emissions limit for CO appears to be based on 10 tests of only one make and model of engine (Caterpillar, Model No. 3508) over a 3-day period in the Research and Development Laboratory of CSU in 1999 (Docket No. EPA–HQ–OAR–2008–0708–0006). The commenter states that according to the engine population data presented in the impacts document in the docket (Docket No. EPA–HQ–OAR–2008–0798–0028) the promulgated rule would impose limits on more than 50,000 CI engines. The commenter believed that basing the limit on such a small and unrepresentative sample jeopardizes the accuracy of any assumptions made about the operational conditions or performance of the regulated population as well as the accuracy of any cost of compliance estimates, and leads to an underestimation of the impact of the rule.

Response: Section 112(d)(3) of the CAA requires EPA to set MACT standards based on the test data that is available to the Agency and this is what EPA did at proposal. EPA recognizes that it had limited emissions test data at the time it developed the proposed rule. However, EPA notes that it used the data that was available at the time of proposal. EPA requested additional test data to supplement the emissions database during the development of previous rules for stationary engines and also in an advance notice of proposed rulemaking for this rule and did not receive any data. EPA again requested additional test data during the comment period for the current engine rulemaking and made an additional effort post-proposal to reach out to industry and other sources in order to supplement the existing emission data set. EPA did receive additional emissions data for stationary CI engines during the post-proposal period for this rulemaking. The additional data include tests for 11 stationary engines, ranging in size from 160 HP to 3,570 HP. The

inclusion of this additional data in the MACT floor analysis for the final rule addresses the commenters' concerns about using data for one large engine to set the MACT floor for smaller engines.

EPA understands the concerns of commenters with regard to whether the MACT floor analysis for the proposed rule took emissions variability appropriately into account. EPA took emissions variability into account to a greater degree when conducting the MACT floor analysis for the final rule. For engines where EPA had data for multiple tests on the same engine, EPA used the highest test run concentration as the representative emissions for that engine. EPA also used the lowest percent reduction observed in determining the percent reduction expected from applicable aftertreatment controls in determining beyond-the-floor MACT standards. Therefore, the variability in emissions from the engine was factored into the MACT floor analysis and the beyond-the-floor MACT analysis.

EPA does not agree that it would be inappropriate to use data from one run in setting MACT floors; using the highest run from the testing takes into account the variability of emissions.

G. Final Rule Impacts

Comment: Several commenters indicated that the costs are not representative of actual costs of implementing the rule and numerous commenters said that the proposed rule will have a significant financial impact on their sources. According to the commenters, EPA has underestimated the cost impacts of the rule by an order of magnitude or more. Numerous commenters indicated that EPA has used old, faulty, and inappropriate data on the cost of controls, testing, recordkeeping and reporting to estimate the economic impacts of the rule. Commenters said that EPA should gather current information on the cost of controls and redo the cost calculations. The commenters provided specific examples of where they believe EPA has used inappropriate cost information. One concern expressed was that the cost of oxidation catalyst control for diesel engines was based on the cost of oxidation catalyst control for gas engines. Commenters also said that not all existing engines have hour meters. Commenters believed that EPA has underestimated the total cost of this rule by underestimating the number of engines requiring the addition of catalyst; assuming that catalysts can simply be added to effectively control existing engines; overlooking the significant cost of field installation; and underestimating the complexity of and administrative/operational burdens added by this rule.

Several commenters provided comments about the economic impact of the rule on emergency units. One commenter stated that overall the cost per ton of HAP or CO removal would be excessive for emergency CI engines since emissions were well below a ton/yr and the units use is very limited and intermittent. Another commenter noted that engine manufacturers do not recommend the use of after treatment devices for emergency engines, and that EPA appeared to support that position in the Regulatory Impact Analysis (RIA), which states that cost per ton removal of HAP ranged from $1 million to $2.8 million for engines larger than 500 HP and from $3.7 million to $8.7 million for engines between 50 and 500 HP. One commenter said EPA does not appear to consider any costs associated with testing emergency engines, even though owners may deem it prudent to test to confirm they are meeting the standard rather than risk an enforcement action if the unit does not meet the standard. Testing to comply with the 100 percent load requirement will require owners to purchase or rent load banks to meet the conditions contemplated in the standard, which can cost up to $10,000 per site. The load bank costs alone could add up to as much as $973 million. In addition, equipment modifications (sample ports) would be necessary to test emissions, and EPA has not included these costs in its calculations.

One commenter said that the proposed rule for existing CI engines greater than 300 HP at area sources is cost prohibitive for facilities with peak shaving engines with low operating hours. The commenter estimated that the cost per ton of HAP removed from these units would range from $200,000 to $1 million, similar to the cost for emergency generators.

While reducing HAP is an important goal, one commenter believed that the overbroad approach taken by EPA in subjecting all the RICE equipment in question to the requirements proposed, regardless of whether the equipment is located in urban or rural areas, particularly when considering the Congressional intent of reducing HAP in urban areas given the potential risks to public health, and the imposition of costs in excess of $528 million to reduce 13,000 tons of HAP a year (*i.e.*, a cost of $40,615 per ton) should be carefully scrutinized.

One commenter noted an additional concern with the proposed rule is the potential impact of parasitic load resulting from the use of catalytic diesel particulate filters (CDPF) and oxidation catalysts. Some back pressure penalty is associated with the use of both CDPF and oxidation catalysts methods to control HAP, the back pressure can increase with time, which may require regeneration of the catalyst or changing filters. The commenter believed that for those utilities that operate RICE with only marginal excess capacity, addition of either type of control could require installation of additional RICE capacity to maintain the needed reliability level. The commenter noted that it will not be possible to design around the pressure drop for existing engines and that the penalty should have been addressed and included by EPA in the cost assessment of retrofit and operation for the control devices.

Another commenter indicated that EPA's estimates are low for the capital and operating costs associated with the use of catalytic control, and are based on pricing data from one vendor and a limited number of data points. The commenter asserted that EPA's capital estimate and annual operating cost estimate for catalytic controls are each low by an order of magnitude of 2 to 3. The commenter also stated that because beyond-the-floor standards (which require catalytic controls) are based on the cost per ton of HAP removed and EPA significantly underestimated capital and operating costs of catalytic controls, EPA must reanalyze the proposed rule with better cost data to determine when catalysts are economically practical.

One commenter said the cost information contained in the docket for test costs is not representative of the sampling costs required to comply with the standards as proposed. Members of the commenter's organization indicated that the cost per sample run using Methods 1, 3, 4, and 10 could easily exceed $10,000, excluding costs to prepare for the sampling (*i.e.*, scaffolding, stack extensions, *etc.*). In addition to these cost considerations, as a practical matter, there would be significant difficulty in performing these EPA test methods on engine exhaust.

The commenter claimed that EPA has proposed compliance requirements that are more stringent than GACT requirements or management practices and that EPA has decided to institute MACT. However, even under MACT EPA can consider cost and energy impacts. The commenter disagreed with EPA's conclusion in the RIA that the rule will not likely have a significant impact on the supply, distribution, or use of energy. The commenter said that the proposed standards could have a

very detrimental impact on energy reliability, and many units may have to be shut down due to the cost of compliance.

Response: EPA used the information it had available at the time of proposal to estimate the cost impacts associated with the rule. This information included cost data obtained for the development of previous stationary engine rulemakings, which EPA believed would be appropriate to use for this rulemaking. Based on the significant number of comments received on the proposed rule costs, EPA revisited its cost analysis and assumptions underlying the proposed rule and revised that analysis and assumptions in the final rule.

EPA has made several attempts to obtain more current cost information, including through an advance notice of proposed rulemaking for this rule. EPA agrees with the commenters that it is inappropriate to base the cost for a diesel oxidation catalyst on the costs for oxidation catalysts for spark ignition engines. Therefore, EPA has based the catalyst cost estimate in the final rule on cost data for diesel oxidation catalysts obtained from a CARB study. More information on the cost estimate can be found in the memorandum entitled "Control Costs for Existing Stationary CI RICE." The cost estimates are based on the use of diesel oxidation catalyst rather than CDPF because we believe that sources will choose to use oxidation catalyst control because they are less costly than CDPF and achieve similar reduction in HAP. Based on a reanalysis of the MACT floor data and above-the-floor options, taking variability into account, the final rule requires engines equipped with catalysts to achieve 70 percent reduction rather than the 90 percent that was proposed.

Regarding the comment that catalysts cannot be added to existing engines, the commenter did not provide any information to show what engines would not be able to be retrofit. Regarding the concerns expressed about backpressure increases, the commenter did not provide any data to support the claim that the backpressure increases are so high that they would severely impact the engine output.

EPA does not agree with the claim that the rule will put a strain on hospitals. The stationary diesel engines at hospitals are typically emergency engines and EPA has determined that emergency engines located at institutional facilities such as hospitals that are area sources are not part of the listed source category and are therefore not subject to the final rule. EPA does not agree with the commenters that it is not appropriate to require peaking units and stationary diesel engines that are located in rural areas to install controls. This is discussed in more detail in the summary of comments and responses. EPA has specified in the final rule that performance testing is not limited to 100 percent load, so it should not be necessary to include the cost of a load bank in the performance testing cost. EPA has incorporated the costs for testing, monitoring, recordkeeping, and reporting in the cost analysis and believes that its estimates for these costs are appropriate. The costs for testing are based on information from source testing companies. As a result of the comments on testing costs, EPA reevaluated the estimate of how many engines could be tested in a single day and determined that two engines could be tested at a facility in one day, rather than three as was estimated in the proposal.

Regarding the concerns expressed by the commenters about the impact of the rule on emergency engines, the final rule requires existing stationary emergency engines to meet work practice or management practice standards, rather than numeric emission limitations; these work practices and management practices do not require that these engines be retrofit with aftertreatment controls or be performance tested to determine compliance. Information provided to EPA by engine manufacturers indicates that most engines are already equipped with an hour meter; therefore, EPA did not add this cost into the rule. EPA does not believe that the final rule will cause owners/operators to replace their emergency engines. The final rule imposes work or management practices on these engines, which EPA believes will not be overly burdensome to facilities and will not cause the retirement of existing stationary emergency engines.

VI. Summary of Environmental, Energy and Economic Impacts

A. What are the air quality impacts?

The final rule is expected to reduce total HAP emissions from stationary RICE by 1,010 tons per year (tpy) beginning in the year 2013 or the first year the rule will become effective. EPA estimates that over 900,000 stationary CI engines will be subject to the rule. These estimates include stationary engines located at major and area sources; however, not all stationary engines are subject to numerical emission standards. Further information regarding the estimated reductions of the final rule can be found in the memorandum entitled "Impacts Associated with NESHAP for Existing Stationary RICE," which is available in the docket.

In addition to HAP emissions reductions, the final rule will reduce other pollutants such as CO, PM, SO_X, and volatile organic compounds (VOC). The final rule is expected to reduce emissions of CO by 14,000 tpy in the year 2013. Reductions of PM are estimated at 2,800 tpy in the year 2013. Emissions of VOC are estimated to be reduced by 27,000 tpy in the year 2013. The final rule will also reduce emissions of SO_X through the use of ULSD. We have not quantified the SO_X reductions that would occur as a result of engines switching to ULSD because we are unable to estimate the number of engines that already use ULSD and therefore we are unable to estimate the percentage of engines that may switch to ULSD due to this rule. If none of the affected engines would use ULSD without this rule, then we estimate the SO_X reductions are 31,000 tpy in the year 2013. If all of the affected engines would use ULSD regardless of the rule, then the additional SO_X reductions would be zero.

B. What are the cost impacts?

The total national capital cost for the final rule for existing stationary RICE is estimated to be $744 million, with a total national annual cost of $373 million in year 2013 (the first year the rule is implemented). Further information regarding the estimated cost impacts of this proposed rule can be found in the memorandum entitled "Impacts Associated with NESHAP for Existing Stationary CI RICE," which is available in the docket.

C. What are the benefits?

We calculated the benefits of this rule in terms of the co-benefits associated with reducing fine particulate matter (PM) rather than calculating the benefits associated with reducing hazardous air pollutants (HAPs). These PM reductions are a consequence of the technologies installed to reduce HAP emissions from RICE. We estimate the monetized $PM_{2.5}$ co-benefits of this final regulatory action to be $940 million to $2.3 billion (2008$, 3 percent discount rate) in the fifth year (2013). The $PM_{2.5}$ co-benefits at a 7 percent discount rate are $850 million to $2.1 billion (2008$). Because the magnitude of the $PM_{2.5}$ co-benefits is largely driven by the concentration-response function for premature mortality, we examined alternate relationships between $PM_{2.5}$ and premature mortality supplied by

experts. Higher and lower co-benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates above.[4]

A summary of the monetized co-benefits estimates at discount rates of 3 percent and 7 percent is in Table 4 of this preamble.

TABLE 4—SUMMARY OF THE MONETIZED $PM_{2.5}$ CO-BENEFITS ESTIMATES FOR FINAL RICE NESHAP

[Millions of 2008$]

Pollutant	Emission reductions (tons)	Total monetized co-benefits (3% discount)	Total monetized co-benefits (7% discount)
Direct $PM_{2.5}$	2,844	$910 to $2,200	$820 to $2,000.
$PM_{2.5}$ Precursors:			
VOC	27,395	$33 to $82	$30 to $74.
Total		$940 to $2,300	$850 to $2,100.

Note: All estimates are for the analysis year (the fifth year), and are rounded to two significant figures so numbers may not sum across rows. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form $PM_{2.5}$. We assume that all PM reductions for this rule are $PM_{2.5}$ reductions. Benefits from reducing hazardous air pollutants (HAPs) are not included.

The benefits estimates of population-level improvements to human health from reductions in $PM_{2.5}$ air pollution. We generated estimates that represent the total monetized human health co-benefits (the sum of premature mortality and morbidity) of reducing a ton of $PM_{2.5}$ and $PM_{2.5}$ precursor emissions. We base the estimate of human health co-benefits derived from the $PM_{2.5}$ and $PM_{2.5}$ precursor emission reductions on the general approach and methodology laid out in the Technical Support Document that accompanied the RIA for the 2008 National Ambient Air Quality Standard for Ground-level Ozone (NAAQS) and Fann *et al.* (2009).[5]

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 co-benefits were divided by the emission reductions to create the benefit-per-ton estimates. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form $PM_{2.5}$. For example, SO_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 co-benefits would be lower.

For context, it is important to note that the magnitude of the PM benefits is largely driven by the concentration response function for premature mortality. Experts have advised EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. For this final rule we cite two key empirical studies, one based on the American Cancer Society cohort study[6] and the extended Six Cities cohort study.[7]

EPA strives to use the best available science to support our benefits analyses. We recognize that interpretation of the science regarding air pollution and health is dynamic and evolving. The question of whether or not to assume a threshold in calculating the co-benefits associated with reductions in $PM_{2.5}$ is an issue that affects the benefits calculations for many EPA rulemakings and analyses. Due to these implications, we solicited comment on appropriateness of both the no-threshold and threshold model for PM benefits analysis as part of the Portland Cement NESHAP (May 2009). The comment period closed on September 4, 2009, and EPA is still reviewing those comments. Since then, EPA finalized the *Integrated Science Assessment for Particulate Matter*,[8] which was reviewed by EPA's Clean Air Scientific Advisory Committee. Based on EPA's review of the body of scientific literature and the *Integrated Science Assessment,* EPA has concluded that the no-threshold model most adequately portrays the relationship between fine particles and premature mortality. Although this document does not necessarily represent agency policy, it provides a basis for reconsidering the application of thresholds in $PM_{2.5}$ concentration-response functions used in EPA's RIAs.

The $PM_{2.5}$ co-benefits for the incremental emission reductions from this final regulatory action reflect EPA's most current interpretation of the scientific literature, including four key changes from previous analyses for refineries: (1) A no-threshold model for $PM_{2.5}$ that calculates incremental co-benefits down to the lowest modeled air quality levels; (2) a revised Value of a Statistical Life (VSL); (3) two technical updates to the population dataset and aggregation method; and (4) presentation of results derived from Pope *et al.* (2002) and Laden *et al.* (2006) instead of using the extremes of EPA's Expert Elicitation on PM Mortality (Roman *et al.,* 2008). For more information on the updates to the benefit estimates, please refer to the RIA for this rule, which is available in the docket.

It should be noted that the $PM_{2.5}$ co-benefits estimates provided above do not include benefits from reduced hazardous air pollutants, improved

[4] Roman *et al.,* 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268–2274.

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

[6] Pope *et al,* 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." Journal of the American Medical Association 287:1132–1141.

[7] Laden *et al,* 2006. "Reduction in Fine Particulate Air Pollution and Mortality." *American Journal of Respiratory and Critical Care Medicine.* 173: 667–672.

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

visibility, reduced aquatic and terrestrial acidification. The benefits from reducing 1,014 tons of HAPs each year have not been monetized in this analysis. We do not have sufficient information or modeling available to provide such estimates for this rulemaking. In addition, we have not quantified the benefits attributable to the SO_2 reductions that would occur as a result of these engines switching to ULSD. Although we are confident that some SO_2 reductions would occur as a result of this rule, we are unable to estimate the percentage of engines that may switch to ULSD in the absence of this rule or the number of engines that already use ULSD. As a $PM_{2.5}$ precursor, these SO_2 emission reductions would lead to fewer $PM_{2.5}$-related health effects. Because of uncertainty in the magnitude of the attributable SO_2 reductions and to avoid the appearance of double-counting, we have chosen to not include these estimates in the results table shown above. If none of the affected engines would use ULSD without this rule, then we estimate the additional monetized $PM_{2.5}$-related health co-benefits would be $720 million to $1.8 billion in 2013 (2008$, 3% discount rate). If all of the affected engines would use ULSD regardless of the rule, then the additional monetized co-benefits from SO_2 reductions would be zero.

This analysis does not include the type of detailed uncertainty assessment found in the 2006 $PM_{2.5}$ NAAQS RIA because we lack the necessary air quality input and monitoring data to run the benefits model. However, the 2006 $PM_{2.5}$ NAAQS benefits 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 costs of this rulemaking are estimated to be $373 million (2008$) in the fifth year, and the monetized $PM_{2.5}$ co-benefits are estimated at $940 million to $2.3 billion (2008$, 3 percent discount rate) for that same year. The co-benefits at a 7 percent discount rate are $850 million to $2.1 billion (2008$). Thus, net benefits of this rulemaking are estimated at $570 million to $1.9 billion (2008$, 3 percent discount rate) and $480 million to $1.7 billion (2008$, 7 percent discount rate). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower co-benefits estimates are plausible, but most of the expert-based estimates fall between the two estimates we present above. EPA believes that the co-benefits are likely to exceed the costs even when taking into account the uncertainties in the cost and benefit estimates.

For more information on the benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

D. What are the economic impacts?

The economic impact analysis (EIA) that is included in the RIA indicates that prices of affected output from the affected industries will increase as a result of the rule, but the changes will be small. The largest impacts are on the electric power generating industry because it bears more costs from the rule than any other affected industry (nearly 80 percent of the total annualized costs). For all affected industries, annualized compliance costs are 0.6 percent or less on average of sales for firms. Thus, output prices will not increase more than 0.6 percent for consumers and producers affected by this rule.

Based on the estimated compliance costs associated with this rule and the predicted changes in prices and output in affected markets, the estimated social costs are $373 million (2008 dollars), which is the same as the estimated compliance costs.

For more information on the benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

E. What are the non-air health, environmental and energy impacts?

EPA does not anticipate any significant non-air health, environmental or energy impacts as a result of the final rule.

VII. 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 or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities.

Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

The information collection requirements in the final rule 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 activities in this final rule include performance testing for non-emergency engines larger than 100 HP, one-time notifications and periodic reports, recording information, monitoring and the maintenance of records. The information generated by these activities will be used by EPA to ensure that affected facilities comply with the emission limits and other requirements. Records and reports are necessary to enable EPA or States to identify affected facilities that may not be in compliance with the requirements. Based on reported information, EPA will decide which units and what records or processes should be inspected. The amendments do not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B, Confidentiality of Business Information.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after sources must comply) is estimated to be 2,232,379 labor hours per year at a total annual cost of $4,200,492. This estimate includes notifications of compliance and performance tests, engine performance testing, semiannual compliance reports, continuous monitoring, and recordkeeping. The total capital costs associated with the requirements over the 3-year period of the ICR is estimated to be $20,444,316 per year. There are no additional operation and maintenance costs for the requirements over the 3-year period of the ICR. 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 in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical

amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

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 final rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. The companies owning facilities with affected RICE can be grouped into small and large categories using Small Business Administration (SBA) general size standard definitions. Size standards are based on industry classification codes (*i.e.,* North American Industrial Classification System, or NAICS) that each company uses to identify the industry or industries in which they operate in. The SBA defines a small business in terms of the maximum employment, annual sales, or annual energy-generating capacity (for electricity generating units—EGUs) of the owning entity. These thresholds vary by industry and are evaluated based on the primary industry classification of the affected companies. In cases where companies are classified by multiple NAICS codes, the most conservative SBA definition (*i.e.,* the NAICS code with the highest employee or revenue size standard) was used.

As mentioned earlier in this preamble, facilities across several industries use affected RICE; therefore, a number of size standards are utilized in this analysis. For the 9 industries identified at the 6-digit NAICS code represented in this analysis, the employment size standard varies from 500 to 1,000 employees. The annual sales standard is as low as 0.75 million dollars and as high as 34 million dollars. In addition, for the electric power generation industry, the small business size standard is an ultimate parent entity defined as having a total electric output of 4 million megawatt-hours (MW-hr) in the previous fiscal year. The specific SBA size standard is identified for each affected industry within the industry profile to support this economic analysis.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This certification is based on the economic impact of this final action to all affected small entities across all industries affected. We estimate that all small entities will have annualized costs of less than 1 percent of their sales in all industries except NAICS 2211 (electric power generation, transmission, and distribution) and NAICS 111 (Crop and Animal Production). For these industries, the number of small entities having annualized costs of greater than 1 percent of their sales is less than 5 percent. Hence, we conclude that there is no significant economic impact on a substantial number of small entities (SISNOSE) for this rule.

For more information on the small entity impacts associated with the final rule, please refer to the Economic Impact and Small Business Analyses in the public docket. These analyses can be found in the Regulatory Impact Analysis for this final rule.

Although the final rule would not have a significant economic impact on a substantial number of small entities, EPA nonetheless tried to reduce the impact of the final rule on small entities. When developing the revised standards, EPA took special steps to ensure that the burdens imposed on small entities were minimal. EPA conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. In this rule, we are applying the minimum level of control (*i.e.,* the MACT floor) to small engines and emergency engines located at major HAP sources and the minimum level of testing, monitoring, recordkeeping, and reporting to affected RICE sources, both major and area, allowed by the CAA. Other alternatives considered that provided more than the minimum level of control were deemed as not technically feasible or cost-effective for EPA to implement for small engines and emergency engines as explained earlier in the preamble.

D. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. This final rule contains 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. Accordingly, EPA has prepared under section 202 of the UMRA a written statement which is summarized below.

As discussed previously in this preamble, the statutory authority for the final rule is section 112 of the CAA. Section 112(b) lists the 189 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP. Section 112(d) of the CAA directs us to develop NESHAP based on MACT, which require existing and new major sources to control emissions of HAP. EPA is required to address HAP emissions from stationary RICE located at area sources under section 112(k) of the CAA, based on criteria set forth by EPA in the Urban Air Toxics Strategy previously discussed in this preamble. These NESHAP apply to existing stationary CI RICE less than or equal to 500 HP located at major sources of HAP emissions, existing non-emergency stationary CI RICE greater than 300 HP, and existing stationary CI RICE located at area sources of HAP emissions.

In compliance with section 205(a), we identified and considered a reasonable number of regulatory alternatives. EPA carefully examined the regulatory alternatives, and selected the lowest cost/least burdensome alternative that EPA deems adequate to achieve the statutory requirements of Clean Air Act section 112 and effectively reduce emissions of HAP.

1. Social Costs and Benefits

The RIA prepared for the final rule, including the Agency's assessment of costs and benefits, is detailed in the "Regulatory Impact Analysis for the Final RICE NESHAP" in the docket. Based on estimated compliance costs on all sources associated with the final rule and the predicted change in prices and production in the affected industries assuming passthrough of costs to affected consumers, the estimated social costs of the final rule are $373 million (2008 dollars). It is estimated that by 2013, HAP will be reduced by 1,010 tpy

due to reductions in formaldehyde, acetaldehyde, acrolein, methanol and other HAP from existing stationary RICE. Formaldehyde and acetaldehyde have been classified as "probable human carcinogens." Acrolein and the other HAP are not considered carcinogenic, but produce several other toxic effects. The final rule is expected to reduce emissions of CO by more than 14,000 tpy in the year 2013. Reductions of PM are estimated at 2,800 tpy in the year 2013. Emissions of VOC are estimated to be reduced by 27,000 tpy in the year 2013. Exposure to CO can affect the cardiovascular system and the central nervous system.

The total monetized benefits of the final rule range from $940 million to $2.3 billion (2008 dollars).

2. Future and Disproportionate Costs

The UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by the rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of the final rule are discussed previously in this preamble. We do not believe that there will be any disproportionate budgetary effects of the final rule on any particular areas of the country, State or local governments, types of communities (*e.g.*, urban, rural), or particular industry segments.

3. Effects on the National Economy

The UMRA requires that we estimate the effect of the final rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material. The nationwide economic impact of the final rule is presented in the "Regulatory Impact Analysis for RICE NESHAP" in the docket. This analysis provides estimates of the effect of the final rule on most of the categories mentioned above. The results of the economic impact analysis were summarized previously in this preamble. In addition, we have determined that the final rule contains no regulatory requirements that might significantly or uniquely affect small governments. Therefore, this rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

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 final rule primarily affects private industry, and does not impose significant economic costs on State or local governments. Thus, Executive Order 13132 does not apply to the final rule.

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

This action does not have Tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on Tribal governments, on the relationship between the Federal government and Indian Tribes, or on the distribution of power and responsibilities between the Federal government and Indian Tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the final rule.

G. Executive Order 13045: Protection of Children From Environmental Health 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 Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is based solely on technology performance.

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

This final rule is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse impact on the supply, distribution, or use of energy. EPA has prepared an analysis of energy impacts that explains this conclusion as follows below.

With respect to energy supply and prices, our analysis suggests that at the industry level, the annualized costs represent a very small fraction of revenue (generally less than 0.6 percent). As a result, we can conclude supply and price impacts on affected energy producers and consumers should be small.

To enhance understanding regarding the regulation's influence on energy consumption, we examined publicly available data describing energy consumption for the electric power sector. The electric power sector is expected to incur about 80 percent of the $373 million in compliance costs associated with the final rule, and is the industry expected to incur the greatest share of the costs relative to other affected industries. The Annual Energy Outlook 2010 (EIA, 2009) provides energy consumption data. Since this final rule only affects diesel-fired RICE, our analysis focuses on impacts of consumption of these fuels. As shown in Table 5 of this preamble, the electric power sector accounts for less than 0.5 percent of the U.S. total liquid fuels (which includes diesel fuel). As a result, any energy consumption changes attributable to the final rule should not significantly influence the supply, distribution, or use of energy nationwide.

TABLE 5—U.S. ELECTRIC POWER[a] SECTOR ENERGY CONSUMPTION

[Quadrillion BTUs]: 2013

	Quantity	Share of total energy use (percent)
Distillate fuel oil	0.12	0.1
Residual fuel oil	0.34	0.3
Liquid fuels subtotal	0.45	0.5
Natural gas	5.17	5.1
Steam coal	20.69	20.6
Nuclear power	8.59	8.5
Renewable energy[b]	6.06	6.0

TABLE 5—U.S. ELECTRIC POWER[a] SECTOR ENERGY CONSUMPTION—Continued

[Quadrillion BTUs]: 2013

	Quantity	Share of total energy use (percent)
Electricity Imports	0.09	0.1
Total Electric Power Energy Consumption[c]	41.18	40.9
Delivered Energy Use	72.41	72.0
Total Energy Use	100.59	100.0

[a] Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[b] Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[c] Includes non-biogenic municipal waste not included above.
Source: U.S. Energy Information Administration. 2009. Supplemental Tables to the Annual Energy Outlook 2010.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113, Section 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. The 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 does not use available and applicable VCS.

This final rulemaking does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

Under § 63.7(f) and § 63.8(f) of Subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required or referenced testing methods, performance specifications, or procedures.

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

Executive Order (EO) 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 increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This rule is a nationwide standard that reduces air toxics emissions from existing stationary CI engines, thus decreasing the amount of such emissions to which all affected populations are exposed.

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 final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2). The final rule will be effective on May 3, 2010.

List of Subjects in 40 CFR Part 63

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

Dated: February 17, 2010.

Lisa P. Jackson,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

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

Subpart A—[Amended]

■ 2. Section 63.6590 is amended by revising paragraphs (b)(1) and (3) to read as follows:

§ 63.6590 What parts of my plant does this subpart cover?

* * * * *

(b) * * *

(1) An affected source which meets either of the criteria in paragraph (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

* * * * *

(3) A stationary RICE which is an existing spark ignition 4 stroke rich burn (4SRB) stationary RICE located at an area source of HAP emissions; an existing spark ignition 4SRB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions; an existing spark ignition 2 stroke lean burn (2SLB) stationary RICE; an existing spark ignition 4 stroke lean burn (4SLB) stationary RICE; an existing compression ignition emergency stationary RICE with a site rating of more than 500 brake HP located at a

major source of HAP emissions; an existing spark ignition emergency or limited use stationary RICE; an existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions; an existing stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; or an existing stationary residential, commercial, or institutional emergency stationary RICE located at an area source of HAP emissions, does not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary.

* * * * *

■ 3. Section 63.6595 is amended by revising paragraph (a)(1) to read as follows:

§ 63.6595 When do I have to comply with this subpart?

(a) * * *

(1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013.

* * * * *

■ 4. Section 63.6600 is amended by adding an introductory paragraph, revising paragraph (c) and adding paragraph (d) to read as follows:

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

* * * * *

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

■ 5. Section 63.6601 is amended by adding a sentence at the beginning of the section to read as follows:

§ 63.6601 What emission limitations must I meet if I own or operate a 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

* * *

■ 6. Section 63.6602 is added to read as follows:

§ 63.6602 What emission limitations must I meet if I own or operate an existing stationary CI RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary CI RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

■ 7. Section 63.6603 is added to read as follows:

§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary CI RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the Federal Aid Highway System (FAHS) you do not have to meet the numerical CO emission limitations specified in Table 2d to this subpart. Existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the FAHS must meet the management practices that are shown for stationary non-emergency CI RICE less than or equal to 300 HP in Table 2d to this subpart.

■ 8. Section 63.6604 is added to read as follows:

§ 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

If you own or operate an existing non-emergency CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. Existing non-emergency CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, or at area sources in areas of Alaska not accessible by the FAHS are exempt from the requirements of this section.

■ 9. Section 63.6605 is amended by revising paragraphs (a) and (b) to read as follows:

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to

reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

* * * * *

■ 10. Section 63.6612 is added to read as follows:

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing CI stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary CI RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

■ 11. Section 63.6620 is amended by revising paragraphs (b) and (c) to read as follows:

§ 63.6620 What performance tests and other procedures must I use?

* * * * *

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.

(c) [Reserved]

* * * * *

12. Section 63.6625 is amended by revising the section heading and adding new paragraphs (e) through (i) to read as follows:

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

* * * * *

(e) If you own or operate an existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions, an existing stationary emergency RICE, or an existing stationary RICE located at an area source of HAP emissions not subject to any numerical emission standards shown in Table 2d to this subpart, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (g)(2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska not accessible by the FAHS do not have to meet the requirements of paragraph (g) in this section.

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

(h) If you operate a new or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary engine that is subject to the work, operation or management practices in items 1, 2, or 4 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil before continuing to use the engine. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

■ 13. Section 63.6640 is amended by:

■ (a) Revising paragraph (a);

■ (b) Revising paragraph (b);

■ (c) Revising paragraph (d);

■ (d) Revising paragraph (e); and
■ (e) Adding paragraph (f) to read as follows:

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

* * * * *

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a new emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed on or after June 12, 2006, or an existing emergency stationary RICE located at an area source of HAP emissions, you must operate the engine according to the conditions described in paragraphs (f)(1) through (4) of this section.

(1) For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as permitted in this section, is prohibited.

(2) There is no time limit on the use of emergency stationary RICE in emergency situations.

(3) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year.

(4) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(4), as long as the power provided by the financial arrangement is limited to emergency power.

■ 14. Section 63.6645 is amended by revising paragraph (a) to read as follows:

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary CI RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary CI RICE less than 100 HP, an existing stationary emergency CI RICE, or an existing stationary CI RICE that is not subject to any numerical emission standards.

* * * * *

■ 15. Section 63.6650 is amended by revising paragraphs (b) and (c)(4) to read as follows:

§ 63.6650 What reports must I submit and when?

* * * * *

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) * * *

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

* * * * *

■ 16. Section 63.6655 is amended by:
■ (a) Revising paragraph (a) introductory text;
■ (b) Revising paragraph (a)(2);
■ (c) Adding paragraph (a)(4);
■ (d) Adding paragraph (a)(5);
■ (e) Adding paragraph (e); and
■ (f) Adding paragraph (f) to read as follows:

§ 63.6655 What records must I keep?

* * * * *

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) * * *

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

(3) * * *

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

* * * * *

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary CI RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency CI RICE.

(3) An existing stationary CI RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

(1) An existing emergency stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary CI RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

■ 17. Section 63.6660 is amended by revising paragraph (c) to read as follows:

§ 63.6660 In what form and how long must I keep my records?

* * * * *

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

■ 18. Section 63.6665 is revised to read as follows:

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal

to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

■ 19. Section 63.6675 is amended:

■ (a) By revising the definition of Diesel fuel;

■ (b) By revising the definition of Emergency stationary RICE;

■ (c) By adding the definition of Black start engine;

■ (d) By adding the definition of Engine startup; and

■ (e) By adding the definition of Residential/commercial/institutional emergency stationary RICE, in alphabetical order, to read as follows:

§ 63.6675 What definitions apply to this subpart?

* * * * *

Black start engine means an engine whose only purpose is to start up a combustion turbine.

* * * * *

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

* * * * *

Emergency stationary RICE means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, *etc.* Stationary CI ICE used for peak shaving are not considered emergency stationary ICE. Stationary CI ICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted under § 63.6640(f). Emergency stationary RICE with a site-rating of more than 500 brake HP located at a major source of HAP emissions that were installed prior to June 12, 2006, may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE with a site-rating of more than 500 brake HP located at a major source of HAP emissions that were installed prior to June 12, 2006, may also operate an additional 50 hours per year in non-emergency situations. All other emergency stationary RICE must comply with the requirements specified in § 63.6640(f).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

* * * * *

Residential/commercial/institutional emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or residences, commercial establishments such as office buildings, hotels, or stores, or institutional establishments such as medical centers, research centers, and institutions of higher education.

* * * * *

■ 20. Table 1a to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 1a to Subpart ZZZZ of Part 63. Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for existing, new and reconstructed 4SRB stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or. b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

■ 21. Table 2a to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 2a to Subpart ZZZZ of Part 63. Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2.	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

■ 22. Table 2b to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 2b to Subpart ZZZZ of Part 63. Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP Located at a Major Source of HAP Emissions, Existing Non-Emergency Compression Ignition Stationary RICE >500 HP, and New and Reconstructed 4SLB Burn Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6601, 63.6630, and 63.6640, you must comply with any operating limitations for new and reconstructed lean burn and existing, new and reconstructed compression ignition stationary RICE:

For each . . .	You must meet the following operating limitation . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst.	Comply with any operating limitations approved by the Administrator.

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(g) for a different temperature range.

■ 23. Add Tables 2c and 2d to Subpart ZZZZ of Part 63 to read as follows:

Table 2c to Subpart ZZZZ of Part 63. Requirements for Existing Compression Ignition Stationary Rice Located at Major Sources of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency CI and black start CI.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; [2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at start-up to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start CI < 100 HP.	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first; [2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI RICE 100≤HP≤300 HP.	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	
4. Non-Emergency, non-black start CI 300<HP≤500.	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start CI>500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

Table 2d to Subpart ZZZZ of Part 63. Requirements for Existing Compression Ignition Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission and operating limitations for existing compression ignition stationary RICE:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI ≤ 300 HP.	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at start-up to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
2. Non-Emergency, non-black start CI 300<HP≤500.	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI > 500 HP.	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
4. Emergency CI and black start CI.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

■ 24. Table 3 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 3 to Subpart ZZZZ of Part 63. Subsequent Performance Tests

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. 2SLB and 4SLB stationary RICE with a brake horsepower >500 located at major sources and new or reconstructed CI stationary RICE with a brake horsepower >500 located at major sources.	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE with a brake horsepower ≥5,000 located at major sources.	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE with a brake horsepower >500 located at major sources.	Limit the concentration of formaldehyde in the stationary RICE exhaust.	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are not limited use stationary RICE.	Limit or reduce CO or formaldehyde emissions.	Conduct subsequent performance tests every 8,760 hrs or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are limited use stationary RICE.	.....	Conduct subsequent performance tests every 8,760 hrs or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

■ 25. Table 4 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 4 to Subpart ZZZZ of Part 63. Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE for existing sources:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE.	a. Reduce CO emissions.	i. Measure the O_2 at the inlet and outlet of the control device; and	(1) Portable CO and O_2 analyzer.	(a) Using ASTM D6522–00 (2005)[a] (incorporated by reference, *see* § 63.14). Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		ii. Measure the CO at the inlet and the outlet of the control device.	(1) Portable CO and O_2 analyzer.	(a) Using ASTM D6522–00 (2005) [a,b] (incorporated by reference, *see* § 63.14) or Method 10 of 40 CFR appendix A. The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE.	a. Reduce formaldehyde emissions.	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005).	(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device.	(1) Method 320 of 40 CFR part 63, appendix A; or ASTM D6348–03 [c], provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130..	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005).	(a) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 of 40 CFR part 63, appendix A; or ASTM D6348–03 [c], provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE.	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005) [a], Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour longer runs.

[a] You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106. ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

[b] You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.

[c] You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

■ 25. Table 5 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 5 to Subpart ZZZZ of Part 63. Initial Compliance With Emission Limitations and Operating Limitations

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. 2SLB and 4SLB stationary RICE >500 HP located at a major source and new or reconstructed CI stationary RICE >500 HP located at a major source.	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. 2SLB and 4SLB stationary RICE >500 HP located at a major source and new or reconstructed CI stationary RICE >500 HP located at a major source.	a. Reduce CO emissions and not using oxidation catalyst.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
3. 2SLB and 4SLB stationary RICE >500 HP located at a major source and new or reconstructed CI stationary RICE >500 HP located at a major source.	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
4. 4SRB stationary RICE >500 HP located at a major source.	a. Reduce formaldehyde emissions and using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
5. 4SRB stationary RICE >500 HP located at a major source.	a. Reduce formaldehyde emissions and not using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
6. Stationary RICE >500 HP located at a major source.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
7. Stationary RICE >500 HP located at a major source.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test. i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
8. Existing stationary non-emergency RICE ≥100 HP located at a major source, existing non-emergency CI stationary RICE >500 HP, and existing stationary non-emergency RICE ≥100 HP located at an area source.	a. Reduce CO or formaldehyde emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
9. Existing stationary non-emergency RICE ≥100 HP located at a major source, existing non-emergency CI stationary RICE >500 HP, and existing stationary non-emergency RICE ≥100 HP located at an area source.	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.

■ 26. Table 6 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 6 to Subpart ZZZZ of Part 63. Continuous Compliance With Emission Limitations and Operating Limitations

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. 2SLB and 4SLB stationary RICE >500 HP located at a major source and CI stationary RICE >500 HP located at a major source.	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. 2SLB and 4SLB stationary RICE >500 HP located at a major source and CI stationary RICE >500 HP located at a major source.	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. 2SLB and 4SLB stationary RICE >500 HP located at a major source and CI stationary RICE >500 HP located at a major source.	a. Reduce CO emissions and using a CEMS	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. 4SRB stationary RICE >500 HP located at a major source.	a. Reduce formaldehyde emissions and using NSCR.	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and ii. reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. 4SRB stationary RICE >500 HP located at a major source.	a. Reduce formaldehyde emissions and not using NSCR.	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. 4SRB stationary RICE with a brake HP ≥5,000 located at a major source.	Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.[a]
7. Stationary RICE >500 HP located at a major source.	Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. Stationary RICE >500 HP located at a major source.	Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing stationary CI RICE not subject to any numerical emission limitations.	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
10. Existing stationary RICE >500 HP that are not limited use stationary RICE, except 4SRB >500 HP located at major sources.	a. Reduce CO or formaldehyde emissions; or b. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit.
11. Existing limited use stationary RICE >500 HP that are limited use CI stationary RICE.	a. Reduce CO or formaldehyde emissions; or b. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit.

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

■ 27. Table 7 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 7 to Subpart ZZZZ of Part 63. Requirements for Reports

As stated in § 63.6650, you must comply with the following requirements for reports:

You must submit a(n) . . .	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in § 63.6650(b)(1)–(5) for engines that are not limited use stationary CI RICE subject to numerical emission limitations; and ii. Annually according to the requirements in § 63.6650(b)(6)–(9) for engines that are limited use stationary CI RICE subject to numerical emission limitations.
	b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or	i. Semiannually according to the requirements in § 63.6650(b).
	c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4).	i. Semiannually according to the requirements in § 63.6650(b).
2. Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in § 63.6650.
	b. The operating limits provided in your Federally enforceable permit, and any deviations from these limits; and	i. *See* item 2.a.i.
	c. Any problems or errors suspected with the meters.	i. *See* item 2.a.i.

■ 28. Table 8 to Subpart ZZZZ of Part 63 is revised to read as follows:

Table 8 to Subpart ZZZZ of Part 63. Applicability of General Provisions to Subpart ZZZZ.

As stated in § 63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions.	Yes.	
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6675.
§ 63.3	Units and abbreviations	Yes.	
§ 63.4	Prohibited activities and circumvention	Yes.	
§ 63.5	Construction and reconstruction	Yes.	
§ 63.6(a)	Applicability	Yes.	
§ 63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources.	Yes.	
§ 63.6(b)(5)	Notification	Yes.	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources.	Yes.	
§ 63.6(c)(1)–(2)	Compliance dates for existing sources	Yes.	
§ 63.6(c)(3)–(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources.	Yes.	
§ 63.6(d)	[Reserved]		
§ 63.6(e)	Operation and maintenance	No.	
§ 63.6(f)(1)	Applicability of standards	No.	
§ 63.6(f)(2)	Methods for determining compliance	Yes.	
§ 63.6(f)(3)	Finding of compliance	Yes.	
§ 63.6(g)(1)–(3)	Use of alternate standard	Yes.	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria.	Yes.	
§ 63.6(j)	Presidential compliance exemption	Yes.	
§ 63.7(a)(1)–(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.
§ 63.7(a)(3)	CAA section 114 authority	Yes.	
§ 63.7(b)(1)	Notification of performance test	Yes	Except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling	Yes	Except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan	Yes	Except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities	Yes.	
§ 63.7(e)(1)	Conditions for conducting performance tests.	No.	Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data.	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes.	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA.	Yes.	
§ 63.7(f)	Alternative test method provisions	Yes.	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting.	Yes.	
§ 63.7(h)	Waiver of tests	Yes.	
§ 63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes.	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No.	
§ 63.8(b)(1)	Monitoring	Yes.	
§ 63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems.	Yes.	
§ 63.8(c)(1)	Monitoring system operation and maintenance.	Yes.	
§ 63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan.	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements.	Yes.	
§ 63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements.	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§ 63.8(d)	CMS quality control	Yes.	
§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS. Except that § 63.8(e) only applies as specified in § 63.6645.
§ 63.8(f)(1)–(5)	Alternative monitoring method	Yes	Except that § 63.8(f)(4) only applies as specified in § 63.6645.
§ 63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that § 63.8(f)(6) only applies as specified in § 63.6645.
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements.	Yes.	
§ 63.9(b)(1)–(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved. Except that § 63.9(b) only applies as specified in § 63.6645.
§ 63.9(c)	Request for compliance extension	Yes	Except that § 63.9(c) only applies as specified in § 63.6645.
§ 63.9(d)	Notification of special compliance requirements for new sources.	Yes	Except that § 63.9(d) only applies as specified in § 63.6645.
§ 63.9(e)	Notification of performance test	Yes	Except that § 63.9(e) only applies as specified in § 63.6645.
§ 63.9(f)	Notification of visible emission (VE)/opacity test.	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(1)	Notification of performance evaluation	Yes	Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded.	Yes	If alternative is in use. Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(h)(1)–(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved. Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	Adjustment of submittal deadlines	Yes.	
§ 63.9(j)	Change in previous information	Yes.	
§ 63.10(a)	Administrative provisions for record-keeping/reporting.	Yes.	
§ 63.10(b)(1)	Record retention	Yes.	
§ 63.10(b)(2)(i)–(v)	Records related to SSM	No.	
§ 63.10(b)(2)(vi)–(xi)	Records	Yes.	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes.	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§ 63.10(b)(3)	Records of applicability determination	Yes.	
§ 63.10(c)	Additional records for sources using CEMS.	Yes	Except that § 63.10(c)(2)–(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes.	
§ 63.10(d)(2)	Report of performance test results	Yes.	
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes.	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§ 63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports.	Yes.	Except that § 63.10(e)(3)(i) (C) is reserved.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§ 63.11	Flares	No.	
§ 63.12	State authority and delegations	Yes.	
§ 63.13	Addresses	Yes.	
§ 63.14	Incorporation by reference	Yes.	
§ 63.15	Availability of information	Yes.	

[FR Doc. 2010–3508 Filed 3–2–10; 8:45 am]

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Federal Register

Friday,
January 18, 2008

Part III

Environmental Protection Agency

40 CFR Parts 60, 63, 85 et al.

Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 63, 85, 90, 1048, 1065, and 1068

[EPA–HQ–OAR–2005–0030, FRL–8512–4]

RIN 2060–AM81

Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is promulgating new source standards of performance for stationary spark ignition internal combustion engines. EPA is also promulgating national emission standards for hazardous air pollutants for new and reconstructed stationary reciprocating internal combustion engines that either are located at area sources of hazardous air pollutant emissions or that have a site rating of less than or equal to 500 brake horsepower and are located at major sources of hazardous air pollutant emissions.

DATES: This final rule is effective on March 18, 2008. The incorporation by reference of certain publications listed in the final rule is approved by the Director of the Federal Register as of March 18, 2008.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2005–0030. EPA also relies on materials in Docket ID No. EPA–HQ–OAR–2005–0029 and incorporates that docket into the record for the final rule. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., 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 EPA Headquarters Library, Room Number 3334, EPA West Building, 1301 Constitution Ave., NW., Washington, DC. The EPA/DC Public Reading Room hours of operation will be 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket and Information Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Jaime Pagán, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541–5340; facsimile number (919) 541–5450; e-mail address *pagan.jaime@epa.gov*.

SUPPLEMENTARY INFORMATION:

Background Information Document. EPA proposed new source performance standards (NSPS) for stationary spark ignition internal combustion engines, and national emission standards for hazardous air pollutants (NESHAP) for stationary reciprocating internal combustion engines that either are located at area sources of hazardous air pollutant emissions or that have a site rating of less than or equal to 500 brake horsepower and are located at major sources of hazardous air pollutant emissions, on June 12, 2006 (71 FR 33803), and received 46 comment letters on the proposal. A background information document BID) ("Response to Public Comments on Proposed Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines") containing EPA's responses to each public comment and the Economic Impact Analysis Report are available in Docket ID No. EPA–HQ–OAR–2005–0030.

Organization of This Document. The following outline is provided to aid in locating information in the preamble.

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G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations.
K. Congressional Review Act

I. General Information

A. Does this action apply to me?

Categories and entities potentially regulated by this action include:

Category	NAICS [1]	Examples of regulated entities
Any manufacturer that produces or any industry using a stationary internal combustion engine as defined in the final rule.	2211	Electric power generation, transmission, or distribution.
	622110	Medical and surgical hospitals.
	335312	Motor and generator manufacturing.
	333912	Pump and compressor manufacturing.
	333992	Welding and soldering equipment manufacturing.
	48621	Natural gas transmission.
	211111	Crude petroleum and natural gas production.
	211112	Natural gas liquids producers.
	92811	National security.

[1] North American Industry Classification System.

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 engine is regulated by this action, you should examine the applicability criteria of the final rule. 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.

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 September 14, 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.

D. Why is EPA not promulgating a final decision for existing stationary reciprocating internal combustion engines?

In the notice of proposed rulemaking for this rule, published on April 12, 2006, EPA proposed maximum achievable control technology (MACT) and generally available control technology (GACT) standards of no emission reductions for existing engines. During the comment period following the proposal, EPA received several comments indicating that the proposed emission standards for existing engines were not appropriate. In addition, since the publication of the proposed rulemaking, the U.S. Court of Appeals for the District of Columbia Circuit issued a ruling on March 13, 2007 involving litigation on the Brick MACT, which set emission standards for major sources. (40 CFR part 63, subpart JJJJJ) that appears to impact EPA's ability to finalize its proposed "no reduction" MACT standards for existing sources. *Sierra Club* v. *EPA*, 479 F.3d 875 (DC Cir 2007). Among other things, the D.C. Circuit found unlawful EPA's no emission reduction control floors, which EPA established for categories in which the best performers used no emission reduction control technology. Because in the proposed rule EPA used a MACT floor methodology similar to the methodology used in the Brick MACT, EPA intends to re-evaluate the MACT floors for existing major sources that have a site rating of less than or equal to 500 brake horsepower consistent with the Court's decision in the Brick MACT case. EPA also intends to re-evaluate the standards for existing area sources in light of the comments received on the proposed rule.

For these reasons, this final rule does not promulgate any standards with regards to existing engines. EPA's plan is to engage in a separate rulemaking process that will focus on existing sources. EPA intends to gather further information on existing engines and then promulgate standards that will take into account the comments it has received, the intervening court decision, and any new information EPA receives as a part of the rulemaking process. EPA expects to propose standards early in 2009.

II. Background

This action promulgates new source performance standards (NSPS) that would apply to new, modified and reconstructed stationary spark ignition (SI) internal combustion engines (ICE). New source performance standards implement section 111(b) of the CAA, 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 standards apply to new stationary sources of emissions, i.e., sources whose construction, reconstruction, or modification begins after a standard for those sources is proposed. The NSPS for stationary SI ICE is promulgated under 40 CFR part 60, subpart JJJJ.

This action also promulgates national emission standards for hazardous air pollutants (NESHAP) from new and reconstructed stationary reciprocating internal combustion engines (RICE) with a site rating of less than or equal to 500 horsepower (HP) located at major sources, and new and reconstructed

stationary RICE located at area sources. The NESHAP are promulgated under 40 CFR part 63, subpart ZZZZ.

III. Summary of the Final Rule

A. What is the source category regulated by the final rule?

The final NSPS apply to new stationary SI ICE. A stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines. The final NESHAP apply only to stationary RICE. To our knowledge, no rotary or other types of stationary ICE exist at this time.

The SI NSPS address emissions from new, modified and reconstructed stationary SI engines. An SI engine is either a gasoline-fueled engine; or any other type of engine, with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are considered SI engines for purposes of the final rule.

The final NESHAP address emissions from new and reconstructed stationary engines less than or equal to 500 HP located at major sources and all new and reconstructed stationary engines located at area sources. A major source of HAP emissions is a plant site that emits or has the potential to emit any single hazardous air pollutant (HAP) at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site. An area source of HAP emissions is a source that is not a major source.

If you are an owner or operator of an area source subject to the final rule, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under the final rule.

1. SI NSPS

New source performance standards for stationary SI engines are issued under section 111(b) of the CAA. All new, modified and reconstructed stationary SI engines are covered regardless of size. The NSPS apply to stationary SI engines combusting any fuel (natural gas, gasoline, liquefied petroleum gas (LPG), compressed natural gas, landfill gas, digester gas, and any other applicable fuel). New source performance standards require these sources to control emissions to the level achievable by best demonstrated technology (BDT), considering costs and any non-air quality health and environmental impacts and energy requirements.

Under section 111 of the CAA, 42 U.S.C. 7411, the Administrator is required to publish, and periodically update, a list of source categories that in his or her judgment cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. This list appears in 40 CFR 60.16. The list reflects the Administrator's determination that emissions from the listed source categories contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare, and it is intended to identify major source categories for which standards of performance are to be promulgated.

EPA has determined that for purposes of NSPS regulations, the stationary internal combustion engine source category should be split into two source categories—SI engines and compression ignition (CI) engines. Final NSPS for stationary CI engines were published on July 11, 2006 (71 FR 39154).

2. NESHAP

The NESHAP portion of this action is a revision to the regulations in 40 CFR part 63, subpart ZZZZ, currently applicable to stationary RICE greater than 500 HP located at major sources, which were promulgated in 2004. When the subpart ZZZZ of 40 CFR part 63 regulations were promulgated in 2004 (69 FR 33474), EPA deferred promulgating regulations with respect to stationary engines 500 HP or less at major sources until further information on the engines could be obtained and analyzed. It was decided to regulate these smaller engines at the same time as EPA regulates engines located at area sources.

This action revises 40 CFR part 63, subpart ZZZZ, in order to address HAP emissions from new and reconstructed stationary RICE less than or equal to 500 HP located at major sources and new and reconstructed stationary RICE located at area sources. For stationary engines less than or equal to 500 HP at major sources, EPA must determine what is the appropriate MACT for those engines under section 112(d)(3) of the CAA.

For stationary engines located at area sources, EPA has the flexibility to promulgate standards based on GACT under CAA section 112(d)(5). EPA listed stationary RICE located at area sources under sections 112(c)(3) and 112(k) of the CAA, and consistent with section 112(c)(3) is establishing standards for the source category in this final rule. The criteria relevant to EPA's listing of this area source category is set forth in the Urban Air Toxics Strategy described in the paragraph below.

On July 19, 1999, EPA announced in the **Federal Register** its plan for addressing exposure to air toxics in urban areas. The strategy addressed sections 112(c)(3) and 112(k)(3)(B)(ii) of the CAA that instruct EPA to identify not less than 30 HAP which, as the result of emissions from area sources, present the greatest threat to public health in the largest number of urban areas, and to list sufficient area source categories or subcategories to ensure that emissions representing 90 percent of the 30 listed HAP are subject to regulation. The strategy included a list of 30 HAP judged to pose the greatest potential threat to public health in the largest number of urban areas (the urban HAP). In the strategy, EPA also listed the area source categories that account for 90 percent of the urban HAP emissions. EPA listed the stationary internal combustion engine source category under section 112(c)(3) and (k) for the following urban HAP: 7 PAH, acetaldehyde, arsenic, benzene, beryllium compounds, cadmium compounds and formaldehyde. Pursuant to section 112(c), the listed area source categories shall be subject to standards under section 112(d) of the CAA.

3. Differentiation by Fuel Type

The final rule differentiates between gasoline, LPG, natural gas, and digester and landfill gas. Gasoline and LPG are fuels more commonly used in nonroad engines than stationary engines. Nonroad SI engines less than or equal to 19 kilowatt (KW) (25 HP) typically use gasoline. It is estimated that about 68 percent of SI nonroad engines above 19 KW (25 HP) use LPG. A smaller

percentage of nonroad SI engines above 19 KW (25 HP) use gasoline (about 23 percent) and even less use compressed natural gas (about 9 percent). Natural gas fuel is more common in larger, stationary applications. Natural gas engines refer to all gaseous-fueled engines except those fueled by landfill and digester gas. Natural gas is primarily composed of methane and typically contains very low levels of sulfur. Other fuels used with stationary SI engines are landfill and digester gases. These gases are by-products of wastewater treatment and land application of municipal reuse. Landfill and digester gases, which are formed through anaerobic decomposition of organic materials, are principally comprised of methane and carbon dioxide, but small quantities of other compounds such as hydrogen sulfide, ammonia, volatile organic compounds, and particulate matter (PM) may also be present. Although similar in composition to natural gas, there are some differences in the emissions from combustion of landfill and digester gases due to e.g., chlorinated compounds are typically not found in natural gas. Both landfill and digester gases contain a family of silicon-based gases collectively called siloxanes. Combustion of siloxanes forms compounds that have been known to foul fuel systems, combustion chambers, and post-combustion catalysts.

B. What are the pollutants regulated by the final rule?

The pollutants to be regulated by the final NSPS for stationary SI engines are nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC). In addition, a sulfur limit on gasoline is being finalized.

The final NESHAP regulate HAP (for areas sources, the NESHAP regulates the seven urban HAP listed above) through formaldehyde, CO, or VOC which EPA has established are appropriate surrogates for HAP emissions from certain engine types.

C. What are the final standards?

A description of the final standards is provided in the following sections.

1. SI NSPS

a. Stationary SI Engines ≤19 KW (25 HP). The final standards affect manufacturers, owners, and operators of stationary SI engines. Engine manufacturers must certify their stationary SI engines with a maximum engine power less than or equal to 19 KW (25 HP) that are manufactured after July 1, 2008, to the certification emission standards for new nonroad SI engines in 40 CFR part 90, as applicable. The standards applicable to these engines are summarized in Table 1 of this preamble.

TABLE 1.—NO_X, HC, NMHC, AND CO EMISSION STANDARDS IN G/KW-HR (G/HP-HR) FOR STATIONARY SI ENGINES >19 KW (25 HP)

Engine class [a]	Emission standards in g/KW-hr (g/HP-hr) [b]		
	$HC+NO_X$	$NMHC+NO_X$ [c]	CO
I	16.1 (12.0)	14.8 (11.0)	610 (455)
I–A	50	.....	
	37	.....	
I–B	40 (30)	37 (27.6)	
II	12.1 (9.0)	11.3 (8.4)	

[a] Class I–A: Engines with displacement less than 66 cubic centimeters (cc); Class I–B: Engines with displacement greater than or equal to 66 cc and less than 100 cc; Class I: Engines with displacement greater than or equal to 100 cc and less than 225 cc; Class II: Engines with displacement greater than or equal to 225 cc.

[b] Modified and reconstructed engines manufactured prior to July 1, 2008, must meet the standards applicable to engines manufactured after July 1, 2008.

[c] $NMHC+NO_X$ standards are applicable only to natural gas fueled engines at the option of the manufacturer, in lieu of $HC+NO_X$ standards.

b. Stationary Non-Emergency SI Gasoline Engines >19 KW (25 HP) and Rich Burn LPG Engines >19 KW (25 HP). Engine manufacturers must certify their stationary non-emergency SI engines with a maximum engine power greater than 19 KW (25 HP) and less than 500 HP that use gasoline or rich burn engines greater than 19 KW (25 HP) and less than 500 HP that use LPG that are manufactured after July 1, 2008, to the certification emission standards for new nonroad SI engines in 40 CFR part 1048, as applicable. Engine manufacturers must certify their stationary non-emergency SI engines with a maximum engine power greater than or equal to 500 HP that use gasoline or rich burn engines greater than or equal to 500 HP that use LPG that are manufactured after July 1, 2007, to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. The standards applicable to manufacturers of non-emergency engines greater than 19 KW (25 HP) that are gasoline or rich burn engines that use LPG are summarized in Table 2 of this preamble.

TABLE 2.—NO_X, HC, AND CO EMISSION STANDARDS IN G/KW-HR (G/HP-HR) FOR MANUFACTURERS OF STATIONARY NON-EMERGENCY SI GASOLINE ENGINES >19 KW (25 HP) AND RICH BURN LPG ENGINES >19 KW (25 HP)

Maximum engine power	Manufacture date	Emission requirement in g/KW-hr (g/HP-hr) [a, b]	
		$HC+NO_X$	CO
25<HP<500 [c]	July 1, 2008	2.7 (2.0)	4.4 (3.3)
	July 1, 2008 (severe duty [e])	2.7 (2.0)	130.0 (97.0)

TABLE 2.—NO_X, HC, AND CO EMISSION STANDARDS IN G/KW-HR (G/HP-HR) FOR MANUFACTURERS OF STATIONARY NON-EMERGENCY SI GASOLINE ENGINES >19 KW (25 HP) AND RICH BURN LPG ENGINES >19 KW (25 HP)—Continued

Maximum engine power	Manufacture date	Emission requirement in g/KW-hr (g/HP-hr) [a, b]	
		$HC+NO_X$	CO
HP≥500 [d]	July 1, 2007	2.7 (2.0)	4.4 (3.3)
	July 1, 2007 (severe duty [e])	2.7 (2.0)	130.0 (97.0)

[a] You may optionally certify your engines according to the following formula instead of the standards in Table 2 of this preamble: $(HC+NO_X)$ $CO^{0.784} \leq 8.57$. The $HC+NO_X$ and CO emission levels you select to satisfy this formula, rounded to the nearest 0.1 g/KW-hr, become the emission standards that apply for those engines. You may not select an $HC+NO_X$ emission standard higher than 2.7 g/KW-hr or a CO emission standard higher than 20.6 g/KW-hr.

[b] Provisions in 40 CFR part 1048 allow engines with a maximum engine power at or below 30 KW (40 HP) with a total displacement at or below 1,000 cubic centimeters (cc) to comply with the requirements of 40 CFR part 90.

[c] Modified and reconstructed engines between 25 and 500 HP manufactured prior to July 1, 2008, must meet the standards applicable to engines manufactured after July 1, 2008.

[d] Modified and reconstructed engines greater than or equal to 500 HP manufactured prior to July 1, 2007, must meet the standards applicable to engines manufactured after July 1, 2007.

[e] Severe-duty engines are engines used in, for example, concrete saws, concrete pumps, and similar severe applications where air-cooled engines must be used. There are expected to be very few, if any, severe-duty stationary engines.

In addition to the emission standards shown in Table 2 of this preamble, there are separate field testing standards required under 40 CFR part 1048 that are part of the certification requirements for engine manufacturers.

c. Stationary Non-Emergency SI Natural Gas Engines 19<KW<75 (25<HP<100) and Lean Burn LPG Engines 19<KW<75 (25<HP<100). Engine manufacturers have the option to certify their stationary non-emergency SI natural gas engines between 25 HP and 100 HP and lean burn LPG engines between 25 HP and 100 HP to the certification emission standards in 40 CFR part 1048, as shown in Table 2 of this preamble. However, the certification is only voluntary, and it is up to the manufacturer to decide if it believes certification is feasible and beneficial. Engine manufacturers may certify engines between 19 and 30 KW (25 and 40 HP) with a displacement of 1,000 cc or less to the provisions of 40 CFR part 90 (shown in Table 1 of this preamble), which is consistent with similar provisions applicable to nonroad engines in this displacement and size category. In addition, for engines manufactured prior to January 1, 2011, manufacturers may alternatively certify to the standards summarized in Table 4 of this preamble applicable to engines greater than or equal to 100 HP and less than 500 HP.

Owners and operators who purchase stationary SI engines with a maximum engine power between 19 and 75 KW (25 and 100 HP) that are natural gas engines or lean burn engines using LPG that are manufactured after July 1, 2008, must meet the NO_X, HC, and CO emission standards in 40 CFR 1048.101(c), as summarized in Table 3 of this preamble.

TABLE 3.—NO_X, HC, AND CO EMISSION STANDARDS IN G/KW-HR (G/HP-HR) FOR OWNERS/OPERATORS OF STATIONARY NON-EMERGENCY SI NATURAL GAS ENGINES 19<KW<75 (25<HP<100) AND LEAN BURN LPG ENGINES 19<KW<75 (25<HP<100)

Maximum engine power	Manufacture date	Emission requirement in g/KW-hr (g/HP-hr) [a, b]	
		$HC+NO_X$	CO
25<HP<100 [c]	July 1, 2008	3.8 (2.8)	6.5 (4.8)
	July 1, 2008 (severe duty)	3.8 (2.8)	200.0 (149.2)

[a] You may apply the following formula to determine alternate emission standards that apply to your engines instead of the standards in paragraph in Table 3 of this preamble: $(HC+NO_X) \times CO^{0.791} \leq 16.78$. $HC+NO_X$ emission levels may not exceed 3.8 g/kW-hr and CO emission levels may not exceed 31.0 g/kW-hr.

[b] For natural gas fueled engines, you are not required to measure non-methane hydrocarbon emissions or total hydrocarbon emissions for testing to show that the engine meets the emission standards of Table 3 of this preamble; that is, you may assume HC emissions are equal to zero.

[c] Modified and reconstructed engines between 25 and 100 HP manufactured prior to July 1, 2008, must meet the standards applicable to engines manufactured after July 1, 2008.

d. Stationary Non-Emergency SI Natural Gas Engines ≥100 HP and Lean Burn LPG Engines ≥100 HP. Owners and operators who purchase stationary SI engines with a maximum engine power between 100 HP and 500 HP that are natural gas engines or lean burn engines using LPG that are manufactured between July 1, 2008 and January 1, 2011, must limit their exhaust emissions of NO_X to 2.0 g/HP-hr, emissions of CO to 4.0 g/HP-hr, and emissions of VOC to 1.0 g/HP-hr. Owners and operators may as an alternative limit their exhaust emissions of NO_X to 160 parts per million by volume, dry basis (ppmvd) at 15 percent oxygen (O_2), emissions of CO to 540 ppmvd at 15 percent O_2, and emissions of VOC to 86 ppmvd at 15 percent O_2 instead of the g/HP-hr limits.

Stationary SI engines with a maximum engine power between 100 HP and 500 HP that are natural gas engines or lean burn engines using LPG that are manufactured after January 1, 2011, must limit their exhaust emissions of NO_X to 1.0 g/HP-hr, emissions of CO to 2.0 g/HP-hr, and emissions of VOC to 0.7 g/HP-hr. Again, owners and operators may as an alternative limit their exhaust emissions of NO_X to 82 ppmvd at 15 percent O_2, emissions of CO to 270 ppmvd at 15 percent O_2, and emissions of VOC to 60 ppmvd at 15 percent O_2 instead of the g/HP-hr limits.

Owners and operators who purchase stationary SI engines with a maximum engine power greater than or equal to 500 HP that are natural gas engines or lean burn engines using LPG that are manufactured after July 1, 2007, must limit their exhaust emissions of NO_X to 2.0 g/HP-hr, emissions of CO to 4.0 g/HP-hr, and emissions of VOC to 1.0 g/HP-hr, except that these standards apply to lean burn engines between 500 and 1,350 HP manufactured after January 1, 2008. Instead of complying with limits in terms of g/HP-hr, owners and operators may limit their exhaust emissions of NO_X to 160 ppmvd at 15 percent O_2, emissions of CO to 540 ppmvd at 15 percent O_2, and emissions of VOC to 86 ppmvd at 15 percent O_2.

Stationary SI engines with a maximum engine power greater than or equal to 500 HP that are natural gas engines or lean burn engines using LPG that are manufactured after July 1, 2010, must limit their exhaust emissions of NO_X to 1.0 g/HP-hr, emissions of CO to 2.0 g/HP-hr, and emissions of VOC to 0.7 g/HP-hr. Instead of complying with limits in terms of g/HP-hr, owners and operators may limit their exhaust emissions of NO_X to 82 ppmvd at 15 percent O_2, emissions of CO to 270 ppmvd at 15 percent O_2, and emissions of VOC to 60 ppmvd at 15 percent O_2.

Engine manufacturers may voluntarily certify their stationary non-emergency SI natural gas engines greater than or equal to 100 HP and lean burn LPG engines greater than or equal to 100 HP, but the certification is not required by the rule. Additionally, for natural gas engines below 500 HP manufactured prior to January 1, 2011, and natural gas engines greater than or equal to 500 HP manufactured prior to July 1, 2010, engine manufacturers may choose to certify their engines to the standards for non-severe duty engines in 40 CFR part 1048 (see Table 2 of this preamble).

A summary of the emission standards that apply to stationary non-emergency SI natural gas engines greater than or equal to 100 HP and lean burn LPG engines greater than or equal to 100 HP are shown in Table 4 of this preamble.

For lean burn LPG engines greater than or equal to 100 HP, manufacturers may certify these engines to the certification emission standards in 40 CFR part 1048 instead of the emission standards shown in Table 4 of this preamble.

TABLE 4.—NO_X, CO, AND VOC EMISSION STANDARDS FOR STATIONARY SI ENGINES ≥100 HP (EXCEPT GASOLINE AND RICH BURN LPG), STATIONARY SI LANDFILL/DIGESTER GAS ENGINES, AND STATIONARY EMERGENCY ENGINES >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards [a]					
			g/HP-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC	NO_X	CO	VOC
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG.	100≤HP<500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60
Non-Emergency SI Lean Burn Natural Gas and LPG.	500≥HP<1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≥HP<1,350).	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	HP≥500	7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500≥HP<1,350).	HP<500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
	HP≥500	7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas lean burn	500≥HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Emergency	25>HP<130	1/1/2009	[b] 10	387	N/A	N/A	N/A	N/A
	HP≥130		2.0	4.0	1.0	160	540	86

[a] Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O_2.

[b] The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_X+HC.

e. Stationary SI Landfill/Digester Gas Engines. Owners and operators who purchase stationary landfill or digester SI engines that are manufactured after July 1, 2007, that are greater than or equal to 500 HP must limit their exhaust emissions of NO_X to 3.0 g/HP-hr, emissions of CO to 5.0 g/HP-hr, and emissions of VOC to 1.0 g/HP-hr, except that these standards apply to lean burn engines between 500 and 1,350 HP manufactured after January 1, 2008. Instead of complying with limits in terms of g/HP-hr, owners and operators may limit their exhaust emissions of NO_X to 220 ppmvd at 15 percent O_2, emissions of CO to 610 ppmvd at 15 percent O_2, and emissions of VOC to 80 ppmvd at 15 percent O_2.

Stationary landfill and digester gas SI engines greater than or equal to 500 HP that are manufactured after July 1, 2010, must limit their exhaust emissions of NO_X to 2.0 g/HP-hr, emissions of CO to 5.0 g/HP-hr, and emissions of VOC to 1.0 g/HP-hr. Instead of complying with limits in terms of g/HP-hr, owners and operators may limit their exhaust emissions of NO_X to 150 ppmvd at 15 percent O_2, emissions of CO to 610 ppmvd at 15 percent O_2, and emissions of VOC to 80 ppmvd at 15 percent O_2.

Stationary SI engines that use landfill or digester gas that are less than 500 HP are given an extra 12 months to comply with the standards. The first stage of limits of 3.0, 5.0, and 1.0 g/HP-hr, for NO_X, CO, and VOC, respectively (or 220, 610, and 80 ppmvd at 15 percent O_2), applies to landfill and digester gas engines manufactured after July 1, 2008. The second stage of limits of 2.0, 5.0, and 1.0 g/HP-hr, for NO_X, CO, and VOC, respectively (or 150, 610, and 80 ppmvd at 15 percent O_2), applies to landfill and digester gas engines manufactured after January 1, 2011. The emission standards applicable to stationary SI landfill and digester gas engines are shown in Table 4 of this preamble.

Engine manufacturers may voluntarily certify their stationary SI landfill and digester gas engines to the emission standards in Table 4 of this preamble, but the certification is not required by the final rule.

f. Stationary Emergency SI Engines >19 KW (25 HP). For stationary SI engines greater than 25 HP that are emergency engines, the final rule sets a single stage of emission limits; however, EPA has determined that it is appropriate to have separate standards for stationary emergency engines above and below 130 HP.

Owners and operators who purchase stationary emergency engines greater than 25 HP and less than 130 HP that are manufactured after January 1, 2009, must limit their exhaust emissions of $HC+NO_X$ to 10.0 g/HP-hr and emissions of CO to 387 g/HP-hr. These standards are consistent with the Phase I emission standards for Class II nonroad engines in 40 CFR part 90.

Owners and operators who purchase stationary emergency engines greater than or equal to 130 HP that are manufactured after January 1, 2009, must limit their exhaust emissions of NO_X to 2.0 g/HP-hr, emissions of CO to 4.0 g/HP-hr, and emissions of VOC to 1.0 g/HP-hr. Instead of complying with limits in terms of g/HP-hr, owners and operators may limit the exhaust emissions from their emergency engines to 160 ppmvd of NO_X at 15 percent O_2, 540 ppmvd of CO at 15 percent O_2, and 86 ppmvd of VOC at 15 percent O_2.

Engine manufacturers may voluntarily certify their stationary emergency SI engines greater than 25 HP, but the certification is not required by the rule, except for manufacturers of gasoline or LPG rich burn emergency engines, who must certify their engines to the standards in 40 CFR part 90 (for engines below 130 HP) or 40 CFR part 1048 (for engines at or above 130 HP—see Table 2 of this preamble).

g. Fuel Requirements. In addition to emission standards, the final rule requires that owners and operators who use gasoline in their stationary SI engine must use gasoline that meets the requirements of 40 CFR 80.195. The requirements include a gasoline sulfur per gallon cap of 80 parts per million (ppm).

2. NESHAP

a. Engines ≤500 HP at Major Sources. Owners and operators of new and reconstructed stationary SI engines with a site rating of equal to or less than 500 HP located at a major source of HAP emissions (except new or reconstructed 4-stroke lean burn (4SLB) stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions), must meet the requirements of the final SI NSPS (40 CFR part 60, subpart JJJJ). Thus, if the owners and operators are in compliance with 40 CFR part 60, subpart JJJJ, they would also be in compliance with 40 CFR part 63, subpart ZZZZ, for engines equal to or less than 500 HP located at a major source (except for 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP located at a major source). The requirements that apply under 40 CFR part 60, subpart JJJJ, were discussed in the previous section of this preamble.

Similarly, owners and operators of new and reconstructed stationary CI engines with a site rating of equal to or less than 500 HP located at a major source of HAP emissions must meet the requirements of the final CI NSPS (40 CFR part 60, subpart IIII). If the owners and operators are in compliance with 40 CFR part 60, subpart IIII, they would also be in compliance with 40 CFR part 63, subpart ZZZZ, for engines equal to or less than 500 HP located at a major source.

Owners and operators of new or reconstructed 4SLB SI stationary engines with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source are required to either reduce CO emissions by 93 percent or more, or limit the concentration of formaldehyde in the stationary engine exhaust to 14 ppmvd or less, at 15 percent O_2. These engines would also be required to meet the requirements in the final SI NSPS, but do not have to comply with the CO emission standards of the SI NSPS if in compliance with the NESHAP.

b. Engines at Area Sources. Owners and operators of new and reconstructed stationary engines located at area sources of HAP emissions must meet the requirements of the final CI NSPS (40 CFR part 60, subpart IIII) or SI NSPS (40 CFR part 60, subpart JJJJ), as appropriate. If the owners and operators are in compliance with either 40 CFR part 60, subpart IIII or JJJJ, as appropriate, they would also be in compliance with 40 CFR part 63, subpart ZZZZ, for new and reconstructed engines located at an area source.

D. What are the requirements for sources that are modified or reconstructed?

1. SI NSPS

The final standards apply to stationary SI engines subject to the SI NSPS that are modified or reconstructed after June 12, 2006. The definitions for modification and reconstruction are given in 40 CFR 60.14 and 40 CFR 60.15, respectively. A stationary engine that is overhauled as part of a maintenance program is not considered a modification if there is no increase in emissions.

Stationary SI ICE less than or equal to 19 KW (25 HP) manufactured prior to July 1, 2008, that are modified or reconstructed after June 12, 2006, are required to meet the standards that apply to engines manufactured after July 1, 2008 (January 1, 2009 for emergency engines).

Stationary SI gasoline and rich burn LPG engines between 25 HP and 500 HP manufactured prior to July 1, 2008, that are modified or reconstructed after June 12, 2006, are required to meet the standards applicable to engines manufactured after July 1, 2008 (January 1, 2009 for emergency engines).

Stationary SI natural gas and lean burn LPG engines greater than 25 HP and less than 100 HP manufactured prior to July 1, 2008, that are modified or reconstructed after June 12, 2006, are required to meet the NO_X, HC, and CO emission standards in 40 CFR 1048.101(c), as summarized in Table 3 of this preamble.

Stationary SI gasoline and rich burn LPG engines greater than or equal to 500 HP manufactured prior to July 1, 2007, that are modified or reconstructed after June 12, 2006, are required to meet the standards applicable to engines manufactured after July 1, 2007.

Stationary SI natural gas and lean burn LPG engines greater than or equal to 100 HP and less than 500 HP manufactured prior to July 1, 2008, that are modified or reconstructed after June 12, 2006, are required to meet a NO_X emission standard of 3.0 g/HP-hr, a CO standard of 4.0 g/HP-hr, and a VOC standard of 1.0 g/HP-hr. Instead of meeting emission standards in terms of

g/HP-hr, owners and operators may meet NO_X, CO, and VOC emission standards of 250, 540, and 86 ppmvd at 15 percent O_2, respectively.

Stationary non-emergency SI natural gas and lean burn LPG engines greater than or equal to 500 HP manufactured prior to July 1, 2007, (or January 1, 2008, for lean burn natural gas engines greater than or equal to 500 HP and less than 1,350 HP) that are modified after June 12, 2006, are required to meet a NO_X emission standard of 3.0 g/HP-hr, a CO standard of 4.0 g/HP-hr, and a VOC standard of 1.0 g/HP-hr. Again, instead of meeting emission standards in terms of g/HP-hr, owners and operators may meet NO_X, CO, and VOC emission standards of 250, 540, and 86 ppmvd at 15 percent O_2, respectively.

Stationary SI landfill and digester gas engines less than 500 HP manufactured prior to July 1, 2008, that are modified or reconstructed after June 12, 2006, are required to meet a NO_X emission standard of 3.0 g/HP-hr, a CO standard of 5.0 g/HP-hr, and a VOC standard of 1.0 g/HP-hr.

Stationary SI landfill and digester gas engines greater than or equal to 500 HP manufactured prior to July 1, 2007, that are modified after June 12, 2006, are required to meet a NO_X emission standard of 3.0 g/HP-hr, a CO standard of 5.0 g/HP-hr, and a VOC standard of 1.0 g/HP-hr. For all modified and reconstructed SI landfill and digester gas engines, instead of meeting emission standards in terms of g/HP-hr, owners and operators may meet NO_X, CO, and VOC emission standards of 220, 610, and 80 ppmvd at 15 percent O_2.

Stationary SI emergency engines greater than or equal to 130 HP manufactured prior to January 1, 2009, that are modified or reconstructed after June 12, 2006, are required to meet a NO_X emission standard of 3.0 g/HP-hr, a CO standard of 4.0 g/HP-hr, and a VOC standard of 1.0 g/HP-hr. Instead of meeting emission standards in terms of g/HP-hr, owners and operators may meet NO_X, CO, and VOC emission standards of 250, 540, and 86 ppmvd at 15 percent O_2. Stationary SI emergency engines between 25 HP and 130 HP manufactured prior to January 1, 2009, that are modified or reconstructed after June 12, 2006, are required to meet a $HC+NO_X$ emission standard of 10.0 g/HP-hr and a CO standard of 387 g/HP-hr.

2. NESHAP

Similar concepts as those discussed above apply to engines subject to 40 CFR part 63 regulations; however, the concept of modification is not included in 40 CFR part 63. The final standards apply to stationary engines subject to the NESHAP that commence reconstruction on or after June 12, 2006, and the reconstruction criteria are provided in 40 CFR 63.2.

E. What are the requirements for demonstrating compliance?

The following sections describe the requirements for demonstrating compliance under the stationary SI NSPS and NESHAP.

1. SI NSPS

Owners and operators subject to the emission standards specified in the final rule who use stationary SI engines with a maximum engine power of less than or equal to 19 KW (25 HP) or who use stationary SI engines with a maximum engine power greater than 19 KW (25 HP) and use gasoline or are rich burn engines greater than 19 KW (25 HP) using LPG must demonstrate compliance by using an engine certified to the emission standards specified in 40 CFR part 90 or 1048, as applicable.

Owners and operators subject to the final rule who use stationary SI engines with a maximum engine power greater than 19 KW (25 HP) that use fuels other than gasoline and that are not rich burn engines greater than 19 KW (25 HP) that use LPG, must demonstrate compliance by either using an engine certified to the emission standards specified in Tables 3 or 4 of this preamble, as applicable, or by conducting an initial performance test (and potentially subsequent performance testing depending on the engine size) to demonstrate compliance with the emission standards.

Owners and operators of all stationary engines subject to the requirements of the SI NSPS must keep records of maintenance conducted on the engine. Owners and operators of stationary non-certified engines, which include certified engines operating in a non-certified manner, must keep a maintenance plan. Owners and operators of certified engines may demonstrate compliance by operating and maintaining their stationary engine and aftertreatment control device (if any) according to the manufacturer's emission-related written instructions and do not have to conduct any performance testing.

Owners and operators of certified engines who do not follow the manufacturer's emission-related operation and maintenance procedures will be considered non-certified engines and will be subject to performance testing. Certified engines operating in a non-certified manner that are less than 100 HP do not have to conduct performance testing to demonstrate compliance. Certified engines operating in a non-certified manner that are greater than or equal to 100 HP and less than or equal to 500 HP, however, must conduct an initial performance test within the first year of engine operation to demonstrate compliance with the emission standards. Finally, certified engines operating in a non-certified manner that are greater than 500 HP must conduct a performance test within the first year of operation and every 8,760 hours of operation or 3 years thereafter to demonstrate compliance. Owners and operators of engines that have never been certified that are greater than 25 HP and less than or equal to 500 HP must conduct an initial performance test to demonstrate compliance with the emission standards. As mentioned, all engines are subject to recordkeeping of maintenance, which includes these engines. Owners and operators of engines that have never been certified that are greater than 500 HP must conduct an initial performance test to demonstrate compliance and must test every 8,760 hours of operation or 3 years after that.

Manufacturers of stationary SI engines required to certify their engines must demonstrate compliance by certifying that their stationary SI engines meet the emission standards, as specified in 40 CFR part 60, subpart JJJJ, as applicable, using the certification procedures in subpart B of 40 CFR part 90 or subpart C of 40 CFR part 1048, as applicable, and must test their engines as specified in those parts. Manufacturers who conduct voluntary certification must follow the same test procedures that apply to large SI nonroad engines under 40 CFR part 1048, but must use the D–1 cycle in International Organization for Standardization (ISO) 8178–4: 1996(E) for stationary engines or the test cycle requirements specified in Table 5 to 40 CFR 1048.505, except that Table 5 to 40 CFR 1048.505 applies to high load engines only.

Manufacturers who opt to voluntarily certify their stationary SI engines to the emission standards specified in this subpart must certify their engines using fuel that meets the definition of pipeline-quality natural gas, which according to the definition must be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units per standard cubic foot.

If the manufacturer chooses to certify its stationary SI engines to another fuel, the manufacturer must specify the properties of that fuel and what adjustments the owner or operator must make to the engine during installation in the field in order to meet the

emission standards. The manufacturer must also perform certification testing on the engine on that fuel, as it would if it was certifying to pipeline-quality natural gas, in order to assure compliance with the emission standards. Manufacturers who conduct voluntary certification of stationary SI ICE must also provide instructions to the owner and operator for configuring the stationary engine to meet the emission standards on fuels that meet the pipeline-quality natural gas specifications and fuels that do not meet the pipeline-quality natural gas specifications. The manufacturer must provide information to the owner and operator of the certified stationary SI engine regarding the particular fuels to which the engine is certified, and instructions regarding configuring the engine in a manner most appropriate for reducing pollutant emissions for engines operating on such fuels.

EPA allows owners and operators of natural gas engines to use propane as back up fuel for emergency purposes for no more than 100 hours per year. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards.

Owners and operators that operate engines that have been certified by the engine manufacturer are not required to perform any performance testing unless the engine is operated outside of the fuel properties or emission-related operation and maintenance procedures specified by the manufacturer. If the owner or operator uses fuels that are outside of the fuel specifications or does not follow the emission-related adjustments or maintenance requirements specified by the manufacturer, the engine is no longer considered a certified engine and the owner or operator must test the engine to demonstrate compliance.

Regarding stationary rich burn engines operating with three-way catalysts or non-selective catalytic reduction, EPA expects that air-to-fuel ratio controllers will be used in conjunction with the control device. The AFR controller must be operated in an appropriate manner to ensure proper operation of the engine and control device in order to minimize emissions.

2. NESHAP

For most engines (i.e. except those discussed in the following paragraph), owners and operators of new and reconstructed stationary SI RICE equal to or less than 500 HP located at a major source of HAP emissions and stationary RICE located at an area source, will be able to demonstrate compliance with the NESHAP if they meet the requirements of the final SI NSPS (40 CFR part 60, subpart JJJJ). Similarly, owners and operators of new and reconstructed stationary CI engines with a site rating of equal to or less than 500 HP located at a major source of HAP emissions, will be able to demonstrate compliance with the NESHAP if they meet the requirements of the final CI NSPS (40 CFR part 60, subpart IIII). If the owners and operators are in compliance with 40 CFR part 60, subpart JJJJ or IIII, as applicable, they will also be in compliance with 40 CFR part 63, subpart ZZZZ, for engines equal to or less than 500 HP located at a major source. The compliance requirements that apply under 40 CFR part 60, subpart JJJJ, were discussed in the previous section. For the majority of stationary CI engines, all that is required under 40 CFR part 60, subpart IIII, is that the owner or operator purchase a certified stationary CI engine and operate it properly and according to the manufacturer's specifications.

Owners and operators of new or reconstructed 4SLB stationary RICE greater than or equal to 250 HP and less than or equal to 500 brake HP located at major source are required to follow the compliance requirements specified in 40 CFR part 63, subpart ZZZZ, consistent with the compliance requirements for 4SLB stationary RICE greater than 500 HP located at a major source. Those compliance requirements include demonstrating compliance by conducting an initial performance test. These engines must also conduct a subsequent performance test semiannually if they are complying with the requirement to reduce CO emissions and not using a continuous emissions monitoring system, and if they are complying with the requirement to limit the concentration of formaldehyde in the stationary engine exhaust. Under the NESHAP, these engines must either reduce CO emissions or limit the concentration of formaldehyde. In addition, these engines would be required to meet the requirements in the final SI NSPS. However, these engines do not have to comply with the CO emission standards of the SI NSPS if in compliance with the NESHAP.

F. What are the reporting and recordkeeping requirements?

The following sections describe the reporting and recordkeeping requirements that are required under the SI NSPS and the NESHAP.

1. SI NSPS

Owners and operators of all engines (certified and non-certified) are required to maintain records of proper maintenance and non-certified engines must keep a maintenance plan. An initial notification is required for owners and operators of engines greater than 500 HP that are non-certified. Also, owners and operators who conduct performance testing are required to report the test results within 60 days of each performance test.

Owners and operators of emergency engines are required to keep records of their hours of operation. For emergency engines greater than or equal to 130 HP, this requirement starts for engines manufactured after the point when more stringent emission standards take effect for non-emergency engines, either in July 2010 or January 2011, depending on the power rating of the engine. For emergency engines below 130 HP, the requirement to keep records of the hours of operation begins for all engines manufactured after January 1, 2009. Owners and operators of emergency engines must install a non-resettable hour meter on their engines to record the necessary information. Emergency stationary engines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. Owners and operators can petition the Administrator for additional hours, beyond the allowed 100 hours per year, if such additional hours should prove to be necessary for maintenance and testing reasons. A petition is not required if the hours beyond 100 hours per year for maintenance and testing purposes are mandated by regulation such as State or local requirements. There is no time limit on the use of emergency stationary engines in emergency situations, however, the owner or operator is required to record the length of operation and the reason the engine was in operation during that time. Records must be maintained documenting why the engine was operating to ensure the 100 hours per year limit for maintenance and testing operation is not exceeded. In addition, owners and operators are allowed to operate their emergency engines for non-emergency purposes for 50 hours per year, but those 50 hours are counted towards the total 100 hours provided for operation other than for true emergencies and owners and operators

may not engage in income-generating activities during those 50 hours. The 50 hours per year for non-emergency purposes cannot be used to generate income for a facility, for example, to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

2. NESHAP

In general, owners and operators of new and reconstructed stationary RICE equal to or less than 500 HP located at a major source of HAP emissions and stationary RICE located at an area source of HAP emissions, will be able to demonstrate compliance with the NESHAP if they meet the requirements of the final SI NSPS (40 CFR part 60, subpart JJJJ) or the final CI NSPS (40 CFR part 60, subpart IIII), as appropriate, which includes reporting and recordkeeping requirements. The reporting and recordkeeping requirements that would apply to stationary RICE were discussed in the previous section of this preamble and in the preamble to the final CI NSPS (71 FR 39154). No additional reporting and recordkeeping requirements are required under the 40 CFR part 63.

Owners and operators of new or reconstructed 4SLB stationary RICE greater than or equal to 250 and less than or equal to 500 brake HP located at major source are required to meet the reporting and recordkeeping requirements specified in 40 CFR part 63, subpart ZZZZ, consistent with the compliance requirements for 4SLB stationary RICE greater than 500 HP located at a major source. The recordkeeping and reporting requirements that apply to these engines were discussed in the preamble to the final RICE NESHAP (69 FR 33473).

IV. Summary of Significant Changes Since Proposal

Most of the rationale used to develop the proposed rule remains the same for the final rule. Therefore, the rationale previously provided in the preamble to the proposed rule is not repeated in the final rule, and the rationale sections of the rule, as proposed, should be referred to. Major changes that have been made to the rule since proposal are discussed in this section with rationale following in the Summary of Responses to Major Comments section.

A. Compliance Dates

In the final rule, EPA has extended the compliance dates for all stationary SI ICE that had a compliance date of January 1, 2008, in the proposal, by 6 months. These engines have a compliance date of July 1, 2008. In addition, stationary SI lean burn engines between 500 and 1,350 HP that had a compliance date of July 1, 2007, in the proposed rule, have also been provided with an additional 6 months, *i.e.*, these engines have a compliance date of January 1, 2008.

B. Distinguishing Sources Based on Size

In the final rule, based on the comments received, EPA is adopting a size threshold of 100 HP for non-emergency stationary SI engines to meet nonroad emission standards. That is, non-emergency stationary SI engines less than 100 HP are subject to the nonroad emission standards in 40 CFR part 90 (if less than or equal to 25 HP) or 40 CFR part 1048 (if greater than 25 HP). Certification to 40 CFR part 1048 is voluntary for all stationary SI engines except gasoline and rich burn LPG engines. Stationary SI engines greater than or equal to 100 HP (except gasoline and rich burn LPG) are subject to the emission standards specified in part 60 subpart JJJJ, as shown in Table 4 of this preamble. Stationary SI lean burn LPG engines have the option of meeting 40 CFR part 1048 instead of the emission standards specified in this subpart. EPA has also provided some flexibility on the initial years of the program for manufacturers to certify to standards in either 40 CFR part 1048 or as shown in Table 4 of this preamble.

C. Hydrocarbon Limit

EPA proposed emission limits for NO_X, CO, and NMHC. In the final rule, EPA is adopting a VOC limit in place of the proposed NMHC limit. The stage 1 and stage 2 emission standards remain as proposed at 1.0 g/HP-hr and 0.7 g/HP-hr, but the standards are for VOC. EPA has defined VOC according to 40 CFR part 51, and has noted that emissions of formaldehyde should not be counted for testing purposes. That is, the final stage 1 and stage 2 emission limits for VOC effectively do not include ethane, methane, and formaldehyde. Formaldehyde was excluded because it cannot be measured by the testing method used to determine the standard; however, EPA expects formaldehyde emissions to be reduced using the emission controls expected for other hydrocarbons and CO. Therefore, we expect formaldehyde emissions to be reduced comparably to VOCs and CO, which are used as a surrogate for formaldehyde for the purposes of section 112.

D. Alternative Limits in Concentration Units

EPA proposed NO_X, CO, and NMHC emission limits in terms of exhaust-based units. Based on various comments and concerns with finalizing emission standards in terms of these units, EPA finds it appropriate to include alternative concentration-based emission limits in the final rule. The concentration-based emission limits, provided in terms of ppmvd at 15 percent O_2, are equivalent to the g/HP-hr emission limits. The owners and operators may choose if they wish to comply with the g/HP-hr standards or the ppmvd standards.

E. Emergency Engine Standards

For stationary emergency engines, EPA proposed that these engines meet emissions standards of 2.0, 4.0, and 1.0 g/HP-hr for NO_X, CO, and NMHC, respectively, for all emergency engines. In the final rule, stationary emergency engines between 25 and 130 HP are subject to emission standards of reduced stringency of 10 g/HP-hr for NO_X+HC and 387 g/HP-hr for CO. Stationary emergency engines greater than or equal to 130 HP are subject to the emission standards as proposed. Stationary emergency engines less than or equal to 25 HP are subject to the emission standards in 40 CFR part 90.

F. Emergency Engine Definition

In the final rule, EPA has retained the proposed definition of stationary emergency engine, except that stationary engines greater than 500 HP located at major sources that were built prior to the proposal date of this rule (June 12, 2006), are subject to the emergency engine definition as finalized in 40 CFR part 60, subpart ZZZZ, on June 15, 2004. All stationary engines built after the date of proposal of this rule are subject to the new definition of stationary emergency engine and are limited to 100 hours per year of maintenance and readiness testing. There is no limit on the time allowed for emergency operation. Stationary emergency engines may be operated for non-emergency purposes for up to 50 hours per year, but those 50 hours are counted towards the 100 hours per year allowed for maintenance and readiness testing. The 50 hours per year for non-emergency purposes cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

G. Manufacturer O&M Requirements

The proposed rule required that owners and operators operate and maintain their stationary SI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. The final rule does not require that owners and operators follow the manufacturer's instructions. Owners and operators who operate and maintain their certified stationary ICE and control device according to the manufacturer's emission-related guidelines are required to keeping records of conducted maintenance and do not have any performance testing requirements under the final rule.

Owners and operators who operate their certified stationary ICE and control device in a manner that is inconsistent with the manufacturer's emission-related guidelines are considered non-certified engines and must keep a maintenance plan, records of conducted maintenance, and must conduct performance testing under the final rule if the engine is greater than or equal to 100 HP. Owners and operators of stationary ICE that have never been certified must keep a maintenance plan, records of conducted maintenance, and must conduct performance testing for all size engines.

H. Streamlined Compliance Requirements

In the final NESHAP, EPA has included a provision that states that owners and operators of new and reconstructed stationary engines less than 500 HP located at major sources and new and reconstructed stationary engines located at area sources (except stationary 4SLB engines between 250 and 500 HP) will be in compliance with the NESHAP requirements if they meet the requirements of the SI NSPS (40 CFR part 60, subpart JJJJ) or the CI NSPS (40 CFR part 60, subpart IIII), as applicable.

V. Summary of Responses to Major Comments

A more detailed summary of comments and EPA's responses can be found in the Summary of Public Comments document, which is available from the rulemaking docket (see **ADDRESSES** section).

A. Compliance Dates

Comment: Several commenters stated that more time is needed to comply with the final rule for owners, operators, and manufacturers. Two commenters said that because there are no existing Federal requirements affecting the vast majority of stationary SI engines and due to the complexity of the regulation, more time is needed to develop the testing and compliance systems for the proposed requirements. Also, two commenters added, that the first compliance date of July 1, 2007, actually occurs prior to the anticipated publication date of the final rule. One commenter expressed that such a regulatory mandate is impractical and unworkable considering the uncertainty of the final regulatory requirements. One commenter believes that an implementation date of January 1, 2008, is unreasonable. This commenter believes that the engine control technology requires significant changes to meet the proposed standards and recommended the implementation date be January 1, 2009, to allow proper development and application time. This commenter explained that a minimum of 12 months is required for manufacturer development and testing such as catalyst configuration changes and component specification for additional engines and fuel types not certified to 40 CFR part 1048. In addition, any deterioration factor service accumulation time required will take 6 months to complete, according to one commenter. Once the development of the systems are complete, this commenter said that it will take manufacturers a minimum of 6 months to apply, or "roll out," this technology to the equipment manufacturer base. The commenter bases this comment on the experience in implementing the large SI nonroad engine regulations (40 CFR part 1048), which began implementation in January of 2004. One commenter requested that the initial compliance dates be delayed 9 months from the proposed compliance dates. Another commenter recommended that the initial compliance dates be delayed until at least 6 to 9 months following publication of the final rule in the **Federal Register**. Sufficient lead time is required not only for manufacturers, but also to allow the many thousands of owners/operators affected by the regulation to be notified and educated regarding the rule's requirements, according to a commenter. Finally, commenter 154 said that subsequent compliance dates also should be delayed by the same amount to assure that the requisite leadtime and stability periods are preserved for manufacturers.

Response: Based on comments received on the proposed compliance dates as summarized in the above comment and on various discussions post-proposal with engine manufacturers, EPA agrees that it is appropriate to extend the proposed compliance date of January 1, 2008, that affected a variety of different engines, many of which are subject to mandatory certification. In the final rule, EPA has provided an additional 6 months for engines that had a compliance date of January 1, 2008 in the proposal. The compliance date in the final rule is July 1, 2008, for engines less than 500 HP. EPA believes that July 1, 2008, will accommodate engine manufacturers and that 6 months will be sufficient lead-time for both owners/operators and manufacturers. In particular, EPA believes July 1, 2008, will provide manufacturers enough time to prepare and complete the certification of new engines. Although the technology already exists for reducing emissions to the level required in the rule, an appropriate amount of time should be provided in order to make the necessary arrangements for engine manufacturers to obtain certification of their products and otherwise assist affected parties prepare for the new standards. EPA's approach is similar to the approach taken in the CI NSPS where sources were required to comply before the final rule was issued, but some time was provided prior to the requirement for mandatory certification. Sections 111 and 112 of the CAA define new engines to be all engines for which construction is commenced following the date of the proposal and it is routine for sources that commenced construction prior to the final rule to be subject to standards under these provisions. Also note that the certification program for large SI engines is voluntary so manufacturers are not being forced to certify engines by those dates. Only engines that are 25 HP or smaller or are gasoline or rich burn LPG-fueled, which are directly related to nonroad engines that are already subject to certification requirements and are also generally smaller than 500 HP, must certify. This is one reason why EPA does not believe that it is necessary to include additional lead-time for large engines (i.e., those above 500 HP) and the compliance date remains as proposed for these engines, i.e., July 1, 2007, with the exception that EPA has granted a delay for certain engines until January 1, 2008, which EPA discusses below.

Regarding the comparison with the large SI nonroad engine rule, EPA notes that the proposal for that rule was published in October 2001, over 2 years from initiation of a mandatory certification program. EPA believes that the compliance dates provide adequate time for manufacturers of engines and

owners/operators to make the necessary preparations and adjustments to develop engines that comply with the emission standards. Additional lead-time has been provided for certain engines, as discussed above, as well as emergency engines. EPA has also provided additional lead-time in order to meet the Stage 2 emission standards. With that said, EPA notes that in the final rule that it has provided lean burn engines in the size range of 500 HP or greater to less than 1,350 HP additional lead-time. Engine manufacturers have indicated that it would be problematic to meet the proposed compliance date. EPA believes that providing engine manufacturers with a later compliance date will make it possible to complete necessary development and implementation work necessary in order to prepare these engines for compliance. More information on this topic can be found in the docket to this rulemaking.

B. Final Hydrocarbon Emission Limits

Comment: Several commenters expressed some concerns with the proposed non-methane hydrocarbons (NMHC) emission standards. One commenter initially recommended a 1.0 g/HP-hr NMHC emissions limit as being technically achievable for most engine applications. However, several engine manufacturers have clarified that the information submitted to EPA regarding achievable NMHC numbers did not include aldehydes and other oxygenated hydrocarbon compounds in the totals. Three commenters recommended that NMHC limitations exclude aldehydes and other oxygenated HC. One commenter said that if the standard includes aldehydes, then the emission standard of 1.0 g/HP-hr is not achievable for most engines, since the initial recommendation the commenter submitted was based on excluding aldehydes from the NMHC totals.

Three commenters requested that ethane be excluded from the calculation of NMHC. They argue that ethane is not a VOC under 40 CFR 51.100(s)(1) and they say that ethane does not contribute to ozone formation. The commenters also noted that natural gases with a relative high content of ethane are primarily present in the western part of the U.S. and commenter 139 provides information indicating that engines are not able to meet the NMHC standards when using natural gas that is high in ethane. Two commenters recommended that EPA examine alternative standards, indices, and testing methods for hydrocarbon emissions. Three commenters said that the parameter to be used for natural gas fueled engines should exclude methane and ethane and have suitable measurement techniques that are applicable in both factory and field tests. One commenter said, if EPA decides to retain NMHC as the appropriate parameter, then at a minimum, the level of the proposed standards needs to be raised or clarification made that the measured HC do not include aldehydes.

Three commenters recommended that if the NSPS includes an emission limit for HC species, the limit should be for VOC (or non-methane non-ethane (NMNEHC)) and not NMHC. Three commenters stated that VOC, not NMHC, are the National Ambient Air Quality Standards (NAAQS) pollutant regulated as an ozone precursor for stationary sources. The commenters believe that most available data are reported as VOC rather than NMHC, and owners/operators are very limited in their ability to assess whether the data indicate that the proposed NMHC standard is achievable for field performance tests. The commenters also believe that before regulating NMHC for stationary engines, EPA should complete an analysis to identify the potential benefit and cost of regulating ethane or using NMHC as a surrogate for VOC for gas-fired engines, and ensure that emissions data from field tests are available to substantiate the basis for the standard.

Several commenters also expressed concern over the proposed test methods for measuring NMHC. Commenters believe that the emissions test methods should be consistent with the included hydrocarbon species, and EPA Method 25 of 40 CFR part 60, Appendix A, should not be used for determination of NMHC or VOC. The commenters support their claim by saying that NMHC emissions are defined as THC emissions less methane emissions. However, this definition needs further clarification to exclude formaldehyde and oxygenates, because the emissions information provided by manufacturers that serves as the basis of the standard does NOT include aldehydes or other oxygenated HC. Non-methane hydrocarbon measurements are typically conducted using a flame ionization detector (FID) to measure THC and a FID or gas chromatography method to measure methane. EPA Method 25A of 40 CFR part 60, Appendix A, uses a continuous FID analyzer to measure exhaust gas THC. Method 18 separates CH_4 (methane) from other exhaust gas species with a gas chromatograph, and quantifies the methane with an appropriate detector. Method 18 of 40 CFR part 60, Appendix A, allows exhaust gas to be collected in a bag or continuously sampled. A flame ionization detector poorly quantifies oxygenated hydrocarbon species. Formaldehyde, and to a lesser extent acetaldehyde, methanol, and acrolein, have been measured in natural gas-fired engine exhaust. The commenters agree with EPA's conclusion that NMHC test methods are simpler and less costly to implement than formaldehyde test methods and that NMHC testing will reduce the testing burden while maintaining emissions compliance assurance. Recognizing that measuring NMHC with a FID does not directly measure formaldehyde and that the emission limits are based on manufacturer data that do not include formaldehyde and other oxygenates, it is important to understand that NMHC is used as a formaldehyde surrogate, but NMHC, the regulated pollutant, does NOT include formaldehyde under this standard. Thus, it is only appropriate to allow test methods that do NOT measure formaldehyde or other oxygenated hydrocarbons; therefore, EPA Method 25 should be excluded from the final rule.

Response: We agree that the composition of certain western gas (i.e. the high concentration of ethane) may make compliance with an NMHC standard more difficult in some cases. As the proposed NMHC standards were intended to ensure compliance with VOC and HAP reduction requirements, and pursuant to 51.100(s) ethane is not a VOC, (nor is it a HAP under CAA section 112(c)) we agree that expressing the standard in terms of VOC, rather than NMHC is appropriate in this case. EPA's final hydrocarbon standards for gaseous fueled and lean burn LPG engines above 100 HP are presented as VOC standards, instead of NMHC standards. For natural gas engines below 100 HP meeting the NMHC standards in 40 CFR part 1048, the regulations do not require measurement of ethane for testing in the field. EPA agrees that EPA Method 25A does not measure formaldehyde and that all data gathered to support the emission limit using this method would not have included formaldehyde. However, EPA Method 25A would measure all other aldehydes and other oxygenated organic compounds although the measured results would be less than the actual concentrations in the gas stream. Even though EPA Method 25A measurements for the other aldehydes and oxygenated organic compounds would have been less than their true values, EPA believes that in all cases the measured values would represent substantially greater than 50 percent of the true value for these compounds. Because these

compounds are accounted for to a significant extent in the database supporting the emission limit it would not be appropriate to exclude them from the definition of VOC. If EPA Method 25A is used to determine compliance with the emission limit, the reduced response of the aldehydes and other oxygenated organics will automatically be taken into account, and the compliance demonstration will be consistent with the procedures used to establish the emission limit. However, if one of the alternative methods, such as EPA Method 18 or EPA Method 320 of 40 CFR part 60, Appendix A, is used, these methods will measure 100 percent of the aldehydes and other oxygenated organic compounds. The results from these methods should be adjusted to account for the bias in EPA Method 25A by multiplying the measured values of the aldehydes and other oxygenated organics by the EPA Method 25A response factor for each measured compound. In addition, when adding the masses of all of the measured VOC from either of these two methods, the actual mass of the aldehydes and oxygenated organics should be reported as the equivalent mass on a propane basis. This will ensure that the results from these two methods are reported on a basis that is consistent with the procedures used to establish the emission limit.

EPA agrees that it is not appropriate to allow EPA Method 25 in the final rule, and EPA has made this clear in the regulatory text. Since the final emission standards are based on data that does not include formaldehyde, it would not be appropriate to include Method 25 since that method may capture that compound.

Further, the emission standards for VOC are based on data that does not include formaldehyde and EPA agrees that it is appropriate to specify that formaldehyde is not included in the final VOC emission standard. EPA has made this clarification in the testing requirements for VOC. In the final rule, EPA has replaced the proposed NMHC limits in g/HP-hr with VOC limits in the same units. In addition, EPA has specified VOC limits in terms of concentration (ppmvd at 15 percent O_2). EPA believes, based on evidence, that a final standard of 1.0 g/HP-hr and 0.7 g/HP-hr for VOC will be achievable for most engines. (Certain engines, like engines burning landfill gases, are subject to less stringent final standards.) The proposed NMHC emission limits are essentially the same as the final VOC emission limits based on how VOC is defined in the final rule. EPA has defined VOC according to the definition provided in 40 CFR part 51, and has noted that formaldehyde is, as discussed, excluded from calculation of VOC emissions. The magnitude of the final VOC limits is the same as the proposed NMHC limits and remain unchanged because the test methods used to capture pollutants are essentially the same.

EPA recognizes that there may be variability in the ethane content in natural gas and believes it would be appropriate to exclude ethane from the final standard. Since EPA has replaced the proposed NMHC standards with VOC standards in the final rule, and since VOC by definition excludes ethane, this comment is resolved.

As discussed, EPA is finalizing emission standards in terms of VOC not as NMHC, as proposed. Based on review of the emissions information used to set the proposed standards for NMHC, comments received on the proposal from industry, and meetings with various stakeholders post-proposal, EPA believes it is more appropriate finalize a VOC standard than an NMHC standard as a measure for HC compounds. Many State regulations affecting stationary sources use VOC and VOC is a more familiar term than NMHC to the regulated community. Emissions of NMHC might be difficult to measure in the field and is a pollutant that has typically been regulated through the manufacturer. Also, because of the variability of ethane in natural gas fuel, VOC, since it excludes ethane, it is more appropriate than NMHC.

C. Emergency Engine Standards

Comment: Several commenters were of the opinion that stationary emergency engines should be exempt from the rule; at a minimum they should be exempt from the emission standards. Two commenters were of the opinion that a size-based exemption threshold or alternative emission limits should be defined for emergency engines. One commenter believes that the proposed NSPS notifications and reporting for small emergency engines will be a cumbersome activity with little environmental benefit. The commenter noted that in most cases emergency engines operated less than 500 hours are not permitted or are considered insignificant due to the limited potential to emit emissions. The commenter requested that EPA consider exempting all emergency engines less than 500 HP from the proposed NSPS and NESHAP regulations. One commenter added that there is little data that show that by regulating these small emergency engines there will be significant environmental improvement. This commenter was of the opinion that as long as hour records are kept to show the engines are being operated in the manner addressed in the EPA white paper mentioned above these engines should be considered insignificant emitters. One commenter requested that EPA exempt stationary emergency engines from the proposed requirements, other than monitoring and recording annual operating hours by owners/operators to demonstrate the engines meet the 100-hour annual operating limitation.

One commenter recommended that emergency engines be exempted from the NSPS and NESHAP. The commenter said that emergency SI engines provide essential and needed services to owners/operators when the normal supply of electricity is disrupted and often serve life-critical functions in times of emergency. The proper operation and function of emergency engines is an essential service, according to the commenter. In addition, because emergency engines operate only during times of emergencies and are limited in hours of operation for maintenance or testing operation, emergency SI engines add minimal emissions to the inventory of criteria or HAP emissions, the commenter added. Commenter 154 believes that there will be negligible emission reductions or environmental benefits from fully applying the requirements of the proposed rule to emergency SI engines. In addition, the commenter said that including emergency engines within the regulations adds a significantly large number of owners/operators to the affected regulatory community, and thus significantly increases the reporting, recordkeeping, and compliance costs of the proposed regulation. Since emissions from emergency SI engines are small and the cost of regulatory compliance and reporting are large, the imposition of NSPS and NESHAP controls on emergency SI engines is not cost-effective, according to the commenter.

Two commenters believe that a 400 HP exemption threshold or alternative emission limits should be defined for emergency engines. The commenters said that 4SLB engines are not available below 400 HP, a size range that comprises the majority of emergency units in the oil and gas industry. The proposed rules would require non-selective catalytic reduction (NSCR) to be applied to these small engines; however NSCR application to an emergency engine has inherent complications, costs, and reliability issues, according to the commenters.

The proposed rule requires controls for emergency engines, whereas the existing RICE MACT concluded controls for emergency units were not necessary and the commenters believe that the proposed rule is therefore more stringent than the existing RICE MACT.

Some commenters also requested that EPA provide an exemption for reconstructed or modified rich burn emergency engines, which would also require post-combustion control to meet the standards.

Two commenters said that if a size-based exemption is not included in the rule, separate subcategories will be needed for emergency engines based on size with emission limits for smaller units commensurate with an uncontrolled rich burn engine, as well as an exemption for existing rich burn emergency engines that are reconstructed or modified.

Response: EPA disagrees that stationary emergency engines should be completely exempted from the rule and also does not agree that emergency engines should be exempt from emission standards. Emergency engines are part of the source category and stationary internal combustion engines and they represent a significant portion of the engines being regulated under these combined rules, and their aggregate emissions are not insignificant. EPA believes that their emissions can be regulated in a manner that is cost-effective and not disruptive. Moreover, given that EPA has already promulgated standards for stationary CI emergency engines, failure to regulate SI emergency engines may create a loophole in regulation. However, as discussed below, EPA believes that a distinction in emission standards based on size is appropriate to include for stationary emergency engines to account for what types of engines and emission controls are available. In addition, EPA agrees that alternative emission limits should be finalized for emergency engines, consistent with the proposal that recognizes a need for different emission standards for emergency engines. The final standards do not require a second stage of more stringent standards for emergency engines. For emergency engines equal to or greater than 130 HP, the standards remain as proposed at 2.0, 4.0, and 1.0 g/HP-hr for NO_X, CO and VOC, respectively. As discussed elsewhere in this document, EPA is also including the option for owners and operators to meet these emission standards in terms of concentration. However, for emergency engines below 130 HP, EPA has found it appropriate to adopt less stringent emission standards in the final rule. Based on information received post-proposal, EPA has learned that there are lean burn engines currently in the market down to 130 HP, and EPA, therefore, disagrees with the commenters who requested a 400 HP exemption threshold or alternative emission limit for emergency engines claiming that 4SLB engines are not available below 400 HP. Information on these engines can be found in the docket. The final emission standards for emergency engines below 130 HP are commensurate with the emission standards that are achievable for rich burn engines without aftertreatment and represent the maximum level of control that is attainable for small emergency engines without using aftertreatment. EPA agrees that requiring NSCR for these engines raises complications and reliability issues that are inappropriate for this subcategory. The final rule requires emergency engines greater than 25 HP and below 130 HP to meet a NO_X+HC standard of 10.0 g/hp-hr and a CO standard of 387 g/HP-hr. These emission standards are consistent with the Phase II standards that apply to Class II nonroad engines.

EPA does not believe that the recordkeeping requirements for emergency engines will be significantly burdensome. Emergency engines have to maintain records hours of operation (of emergency and non-emergency use) to ensure they are not operated beyond the 100-hour limit of the rule. Small emergency engines, i.e., those less than 130 HP will be required to begin recordkeeping immediately. However, since there is no difference between the emission standards for emergency and non-emergency engines above 130 HP until the stage 2 emission standards become effective for non-emergency engines, these larger emergency engines do not have to begin recording hours of operation and keep records of total hours of operation until July 1, 2010 or January 1, 2011, depending on whether the emergency engine is greater than or equal to 500 HP or below 500 HP, respectively.

EPA has made simplifications in the final rule that would affect emergency engine compliance requirements. In the final NESHAP, EPA has included a provision that allows emergency engines subject to the NESHAP that are new or reconstructed and equal to or less than 500 brake HP located at a major source of HAP emissions or located at an area source of HAP emissions to meet the requirements of the NESHAP by demonstrating compliance with the SI NSPS. EPA believes that this provision greatly reduces the compliance burden for owners and operators of emergency engines and overall simplifies the compliance process. Further, under the final SI NSPS, engines less than 100 HP that are certified or that were certified, but are operated in a non-certified manner will not be subject to any performance testing. This would include emergency engines.

EPA recognizes that this final rule is more stringent than the existing RICE NESHAP covering stationary engines greater than 500 HP at major sources, but EPA sees nothing improper about adopting more stringent standards affecting emergency engines under this rule. EPA often promulgates more stringent requirements in rules subsequent to initial rules regulating a source category. Emergency engines covered by the previous NESHAP are not subject to this rule. Only new, modified or reconstructed engines installed after the publication date of the notice of proposed rulemaking for this rule are subject to the more stringent requirements, except that EPA has added explicit limitations on use of emergency engines for peak shaving and supplying power to an electric grid or that supply power as part of a financial arrangement with another entity.

Regarding the request for an exemption for modified and reconstructed rich burn emergency engines, EPA disagrees that an exemption should be provided. The overall goal of the statute for modified and reconstructed engines is that older engines that are being modified or reconstructed should be subject to relatively the same standards as new engines. This reduces the incentive for owners and operators to continue to use older dirtier engines for very long periods beyond their normal life. It is not impossible to apply add-on controls to emergency engines.

D. Emergency Engine Definition

Comment: One commenter stated that the proposal sets separate standards for new emergency engines, but fails to impose enforceable limits so that these engines will be used only in clearly defined emergencies. The commenter strongly supports EPA's specification of emissions standards for emergency engines and to require that emergency engines be equipped with non-resettable meters. In addition to these requirements, the commenter said that EPA must require that emergency engines that do not meet otherwise applicable emissions limits be labeled as such. Additionally the commenter said that EPA must tighten the definition of a stationary emergency engine. According to the commenter, by

allowing emergency engines to run for an unlimited number of hours during emergency situations, but failing to provide a clear definition of what constitutes an emergency situation or emergency operation, the proposed rule leaves a highly problematic loophole. The commenter further noted that since the requirements for emergency engines are not as stringent as those for non-emergency engines, there could be a positive economic incentive for consumers to purchase an emergency engine even if that is not the engine's intended use. To close this loophole and effectuate the rule's intent, the commenter said that EPA must provide an unequivocal definition of what constitutes an emergency situation and emergency operation. The commenter advocated that a clear and stringent definition is needed to prevent operators of emergency engines from running these engines for an unlimited number of hours without triggering the more stringent Phase 2 controls required of non-emergency engines.

EPA's proposed definition does preclude one specific activity from being classified as an emergency situations (i.e., peak shaving), but it is otherwise far too general. According to the commenter, by including only examples of what constitutes an emergency engine, EPA is leaving the definition open to too much interpretation. The commenter recommended that at the least, the definition of an emergency engine should replicate the language used for stationary CI engines in stating that "Stationary (CI) ICE used to supply power to an electric grid or that supply power as part of a financial agreement with another entity are not considered to be emergency engines."

The commenter further suggested that the following elements be incorporated into the definition of an emergency stationary internal combustion engine:

- The definition should require that the situation be truly unforeseeable, beyond the control of the owner or operator, and not part of any contractual obligation. In particular, the definition should exclude operation for purposes of supplying power for distribution to the electric grid and operation for training purposes.
- The definition should exclude equipment failure or other failure to comply with any environmental law caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. This will ensure the proper incentives are in place for care and maintenance of non-backup engines.

The commenter also said that if EPA finalizes its intent to allow natural gas-fired stationary SI engines to operate on propane fuel for up to 100 hours per year for emergency operations, a comprehensive analysis should be undertaken to evaluate the full emissions implications of what appears to be a somewhat arbitrary relaxation of the proposed standards.

Response: EPA agrees that requiring emission standards for stationary emergency engines and requiring that emergency engines be equipped with non-resettable hour meters, but disagrees that the definition of emergency engine creates a loophole. EPA believes it proposed an adequate definition and it is not possible to include every possible situation that might constitute an emergency in the definition. EPA agrees that it is important to provide language that minimizes the possibility of affected sources avoiding more stringent requirements. EPA believes the definition is clear, and furthermore, believes that the requirement to keep records of the hours of operation of the engine in emergency and non-emergency situations will prevent misuse. EPA does agree with the commenter that it is appropriate to tighten the definition as far as precluding certain activities and has included in the definition of emergency engine that stationary SI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines. This language is consistent with the final CI NSPS. As for the comment related to labeling of emergency engines, EPA proposed in § 60.4242(d) that manufacturers label their emergency engines that only meet the emergency engine emission standards as such and that the engine is for emergency use only. This requirement has been retained in the final rule, and EPA believes this satisfies the commenter's concern on this topic.

Regarding the comment on EPA's provision allowing natural gas-fired stationary SI engines to operate on propane fuel for up to 100 hours per year for emergency operations, EPA included that provision to provide flexibility in emergency situations when the main fuel may not be available. EPA believes such an allowance is appropriate and does not expect that emissions will be significantly affected by including a provision to operate on propane for 100 hours per year for emergency purposes. Numbers EPA has available, which are presented in information included in the docket to the proposed rule, show that regulated pollutant emissions (NO_X, CO, and VOC/NMHC/THC) from engines running on propane are the same or lower than emissions from engines running on natural gas (rich burn and lean burn), with a few exceptions. Therefore, for the reasons provided, it is not expected that the propane allowance will significantly affect emissions and EPA has retained the propane use allowance in the final rule.

Comment: Two commenters believe that the emergency engine requirements in the proposed NSPS/NESHAP are more restrictive than the requirements in the RICE NESHAP. The commenters believe the proposed rules should be amended to be consistent with the emergency engine definition and exemption provided in the RICE NESHAP. Two commenters said that the emergency engine definition in the existing RICE MACT that was developed based on input and review from a broad stakeholder group should be retained. The commenters believe that the proposed rule substantially and materially alters the definition as follows:

- Maintenance and readiness testing limited to 100 hours per year versus no time limit on the use of emergency stationary RICE for routine testing and maintenance.
- Elimination of an additional 50 hours per year in non-emergency situations.
- Requirement to maintain documentation for maintenance and testing operation to ensure the 100 hour per year limit is not exceeded.
- Maintenance and readiness testing operation provisions as recommended by third party Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine has been introduced.

The commenters believe that the current NESHAP places no restriction on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance. In addition, it offers an additional 50 hours per year in non-emergency situations. This clause was included as an outcome of the industrial combustion coordinated rulemaking (ICCR) process to provide adequate time to tests systems related to the emergency unit. For example, firewater systems where engine checks are necessary, and a systems check is also required and may be completed as part of a safety exercise. Commenter 150 believes that EPA has confused the additional non-emergency allocation with a perceived hour restriction for

annual maintenance and readiness checks.

Also, the commenter stated that in consideration relative to the RICE MACT, the proposed NESHAP amendments broaden the category of affected equipment to include units that are less than or equal to 500 HP and area sources. With more stringent criteria in the proposed rule, the commenter believes that EPA is requiring more stringency for small engines and area sources than what was deemed necessary for larger engines under the existing RICE MACT. Further, the added burden and cost associated with documenting and maintaining records describing why the engine was operating must be assessed and the benefit for this requirement rationalized. As an alternative to continuing with the revised definition in the proposed rule, the commenters recommend that the current definition be retained.

Response: It is true that EPA proposed a more stringent emergency engine definition and requirements as compared to the existing RICE MACT emergency engine definition. Regarding the commenters' request to retain the existing RICE MACT definition, EPA believes that keeping the proposed definition is appropriate for the most part. EPA recognizes that the existing definition was based on input and review from industry, and EPA is not ignoring the products of the ICCR process nor the extensive participation and commitment of industry members. However, EPA has learned a lot since the ICCR process from 10 years ago and knows now that there are health consequences for failing to regulate emergency engines and for having a broad definition that allows engines that are used for more than emergencies to emit at higher levels. EPA feels the existing RICE MACT definition of emergency engines was not given appropriate restrictions and would unintentionally allow significant operation of an engine in non-emergency situations such as the unlimited maintenance allowance.

Based on vast information received since the time of the ICCR process and the RICE MACT rulemaking, EPA has concluded that it is appropriate to limit the hours of operation during maintenance and testing to 100 hours per year. The issue of allowable hours for maintenance and testing was discussed extensively under the CI NSPS rulemaking and more information can be found in the final CI NSPS rule (71 FR 39153) and Responses to Comments (RTC) document (see EPA–HQ–OAR–2005–0029–0324). EPA recognizes that the existing RICE MACT places no restriction on the use of emergency engines in emergency situations and for routine maintenance and testing. EPA agrees that is appropriate to retain a no time limit on the use of emergency stationary engines in emergency situations; however, does not agree that routine maintenance and testing should be unlimited. Again, EPA has gained much information regarding emergency engine operation since the ICCR process a decade ago and must consider environmental and health consequences for failing to regulate the operation of emergency engines appropriately and prevent loop-holes. Numerous comments received during the public comment period for NSPS for stationary CI engines argued that EPA should allow 100 hours per year for emergency engines to conduct necessary maintenance and testing. Based on those comments, EPA continues to believe that it is appropriate to finalize a 100 hours per year limit for maintenance and testing operation for emergency engines under the NSPS. EPA disagrees that maintenance and testing should be unrestricted. However, EPA believes it is crucial to allow sufficient hours for maintenance and readiness testing to ensure that the emergency engine will respond as expected in the event of an emergency, and EPA believes that 100 hours per year is adequate.

The commenters expressed particular concern over the elimination of the additional 50 hours per year for non-emergency situations included in the original RICE MACT emergency engine definition, but excluded from the proposed requirements affecting emergency engines in this rule and EPA understands the commenters' concerns. It is true that in the preamble to the proposed rule, EPA confused the existing 50 hours per year currently allowed for non-emergency operation in the RICE MACT with the 100 hours per year for maintenance and readiness checks, and may be, as the commenters indicated, a result of comparing the SI NSPS too closely to the CI NSPS that was recently promulgated. Industry has expressed that it might be forced to use portable emergency engines instead of stationary emergency engines to avoid certain requirements of the rule and indicated that the portable engines will be dirtier than the stationary engines. EPA certainly does not wish to create such outcome of the rulemaking and therefore believes it is appropriate to allow owners/operators to operate their engines for 50 hours per year for non-emergency purposes and has made that clarification in § 60.4243(d) of the final rule. However, EPA is concerned that if stationary emergency engines are allowed to operate in non-emergency situations they may be inappropriately used for peaking power. In response to EPA's concern, industry has noted that its intent is not to use stationary emergency engines for peaking purposes. Even so, EPA has specified that the 50 hours allowed for non-emergency situations cannot be used to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. If this happens, the engine is no longer considered to be an emergency engine and the engine would be required to meet the non-emergency engine emission standards, which are more stringent. In addition, the allowed 50 hours of operation for non-emergency situations must be within the currently allowable 100-hour total for purposes of maintenance and testing. In other words, the total hours of operation per year cannot exceed 100 hours for purposes of maintenance and testing and for running the engine for non-emergency purposes.

Regarding the requirement to maintain records to ensure the 100-hour limit is not exceeded for emergency engines as specified in § 60.4245(b) of the proposed rule, EPA feels this requirement is necessary and appropriate. This requirement is consistent with the final CI NSPS (see 40 CFR 60.4214(b)). To ensure compliance with the 100-hour limit, EPA must require recordkeeping for all operation of emergency engines, emergency situations as well as required testing. This is a reasonable way to enforce this limit to ensure that the non-emergency hours of operation are not exceeded beyond allowable limits. Clearly, this requirement yields environmental benefits since it will limit the likelihood that sources subject to the rule that operate emergency engines would exceed the 100-hour annual non-emergency limit. As noted in the RTC document for the final CI NSPS, many States require reporting of both emergency and non-emergency use, e.g., the California ATCM requires a monthly log of all operation by emergency engines. Also, certain facilities already maintain such documentation, e.g., operating hours and operating conditions are currently maintained at hospitals. EPA wishes to prevent owners/operators from operating emergency engines illegally and circumventing the regulation and believes the additional recordkeeping requirements will greatly enhance EPA's ability to enforce this requirement. The

requirement will ensure that there is documentation that the engine was operating in emergency situations when it was running beyond the annual limits permitted for maintenance and testing. There is no annual cap on the hours of operation during an emergency situation, but it is important to have documentation that such operation was indeed for emergency purposes. As noted, owners/operators of emergency engines already keep documentation of when and why such engines were operated so EPA feels the recordkeeping requirement is no significant additional burden.

However, EPA does believe it is necessary to clarify that emergency engines above 500 HP at major sources that were installed prior to the proposal date for this rule (June 12, 2006), but after the proposal date (December 19, 2002) for the previous RICE MACT (and thus, new emergency engines under 40 CFR part 63, subpart ZZZZ, and subject to the old rule) should be governed by the old definition of emergency engines, except that the definition includes the clarification that emergency engines do not include engines used for peaking power or to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. This clarification has been made to the definition of emergency stationary RICE in section 63.6675 of the final rule. EPA believes this clarification addresses some of the commenters' concerns on this issue.

Comment: One commenter stated that by reducing the scope of engines that qualify as "emergency engines," the proposed revision could expand the universe of engines that are subject to more stringent NESHAP requirements. Commenter 145 believes that its member utilities would be directly affected, since they deploy emergency engines to support their obligation to deliver energy to customers safely and reliably. In addition, this revision would impact utility customers who deploy emergency engines, such as hospitals and nursing homes, since there is no minimal size threshold on the engines affected by the proposal.

Response: EPA disagrees that the rule necessarily expands the universe of engines that are subject to the standards applicable to non-emergency engines. Operation of engines during emergencies is not restricted by the rule and if an engine is truly an emergency engine, it would not be subject to more stringent requirements. Available information indicates that emergency engines operate on average about 50 hours per year, which includes the hours spent for maintenance and testing purposes. EPA recognizes that there may be stationary emergency engine applications that operate beyond 50 hours per year for maintenance and testing purposes, which is why EPA proposed a 100-hour allowance for such purposes. EPA received numerous comments on the testing and maintenance allowance on the proposed CI NSPS. Based on the number of commenters who indicated that the proposed maintenance and testing allowance of 30 hours per year was not enough, EPA chose to increase the number to 100 hours per year, which was consistent with what commenters recommended. Even though the original RICE NESHAP covering stationary engines greater than 500 HP located at major sources did not have a time limit on the use of emergency stationary engines for routine testing and maintenance, EPA believes that providing 100 hours per year is more than sufficient. In those few cases where 100 hours is not sufficient, EPA has included the provision allowing owners/operators to petition for additional hours (unless the owner/operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year, in which case, a petition is not necessary.) Note, however, that in the final rule, EPA has made it clear that "new" engines affected by the NESHAP that are installed prior to the proposal of the NSPS would be covered by the old definition included in the original NESHAP at 40 CFR part 63, subpart ZZZZ. In addition, EPA has specified that 50 of the 100 hours allowed for maintenance and testing can be use for non-emergency purposes.

E. Manufacturer O&M Requirements

Comment: Several commenters expressed concern over the proposed requirements requiring owners/operators to operate and maintain SI ICE according to the manufacturer's written instructions or procedures developed by the owners/operators that are approved by the engine manufacturer. One commenter believes that compliance requirements should reflect best practices developed by the owners/operators with experience with using the engines in the field. Another commenter felt that the manufacturers do not have the long-term experience in operating and maintaining these engines in the field and recommended that the proposed NESHAP allow owners/operators to use the existing maintenance requirements of the General Provisions of both the NSPS (40 CFR part 60, subpart A) and the NESHAP (40 CFR part 63, subpart A) rules to meet the requirements of this rule.

One commenter recommended for voluntarily certified engines, the owners/operators be given a choice of either accepting the manufacturers certification or opting for a "verification program" modeled after the performance testing of § 60.4243(d)(2) of the proposal.

One commenter expressed that it is in general agreement that owners/operators should maintain their SI ICE in accordance to the original manufacturer's specifications for larger engines. However, the commenter had concerns about imposing these requirements on limited use and small engines. The commenter believes that this requirement does not appear to be commensurate with the environmental impact.

One commenter expressed that the operation and maintenance (O&M) requirements in manufacturer's manuals is too stringent and inflexible and needs to be changed and stated that engine manufacturers do not want to become involved in approving or reviewing procedures developed by owners/operators. The commenter added that in many cases, owners/operators of stationary engines have developed and follow their own O&M procedures and have extensive experience in operating their engines to optimize performance and life in their specific applications within regulatory emissions limits. Further, the commenter said, owners/operators of non-certified engines are required to conduct performance testing to assure compliance. Therefore, since these owners/operators will use other means to assure compliance, there should not be a regulatory requirement to follow manufacturer's procedures, the commenter expressed. However, if EPA includes the requirement to follow engine manufacturer's procedures in the final rule, the referenced procedures should be limited to those required to maintain emissions control, the commenter said, and recommended that EPA develop a suite of options and requirements to assure compliance as follows:

- For certified engines, owners/operators should be required to set up the engine and follow manufacturers' recommended maintenance, but only for systems or components that affect emissions.
- For non-certified engines, appropriate emissions testing and monitoring should be all that is required.
- In addition, owners/operators should be able to purchase a certified

engine but operate it according to their own procedures. In that case, appropriate emissions testing and monitoring should be all that is required.

One commenter's objection to the proposed requirement to follow the manufacturer's procedures was based on the assertion that most operators of these engines have developed proprietary procedures for their engines, varying from region to region and across the broad spectrum of applications of these engines; that reviewing procedures would subject engine manufacturers to an administrative burden. This requirement is unnecessary, the commenter noted, because owners/operators bear responsibility for compliance, and are already required to demonstrate such compliance through extensive testing.

Two commenters requested that EPA allow owners/operators to define O&M requirements for gas-fired engines, rather than the manufacturer O&M. These two commenters stated that owners/operators have developed and refined O&M practices to address the specific challenges, rigor, and accessibility of their application. However, if EPA chooses to mandate manufacturer O&M, then the commenters requested that the manufacturers be required to reasonably review and approve alternatives, and the cost of the program be borne by the manufacturer. One commenter stated that allowing owners/operators to follow their own O&M procedures is consistent with the requirements of the subpart A General Provisions. The commenter stated that the EPA should clearly indicate that owners/operators of gas-fired engines can choose compliance monitoring based on owners/operators defined O&M and periodic tests even if a certified engine is available.

Response: EPA agrees with some of the comments received on the issue of operating the engine according to manufacturer O&M procedures. EPA agrees that any requirement to operate and maintain engines according to manufacturer instructions should be limited to emission-related operation and maintenance. In addition, in the final rule, EPA has not included the requirement for owners/operators of non-certified engines to operate and maintain their engines according to the manufacturer's written instructions or procedures developed by the owners/operators that are approved by the engine manufacturer. Instead, owners/operators will be required to operate and maintain their engines in a proper manner, consistent with their own maintenance plan. Owners and operators of non-certified engines will be required to keep records of the maintenance performed on the engine. In addition, EPA is requiring performance testing of non-certified engines to demonstrate compliance with the emission standards, consistent with the proposal.

Based on information received during the final rulemaking and in public comments, EPA does not believe it is appropriate to require manufacturer O&M procedures for all owners/operators of certified engines without allowing alternative procedures and is therefore providing an alternative option to owners/operators. However, if an owner/operator has a certified engine that it wishes to operate according to its own well-established procedures based on its own experience with operating that engine (or engines), that particular engine that was originally certified will no longer be considered certified and the engine must be tested. EPA will consider that engine to be operating in a non-certified manner, and will require testing if the engine is greater than or equal to 100 HP. Engines below 100 HP operating in a non-certified manner will be exempt from performance testing, but are required to keep a maintenance plan and records. EPA wishes to encourage the certified route for smaller engines and expects that the majority of engines in this size group will be certified. Engines greater than or equal to 100 HP and less than or equal to 500 HP will be required to conduct a performance within 1 year of startup to demonstrate compliance with the emission standards. These engines will in addition be required to keep a maintenance plan and records of conducted maintenance. Engines greater than 500 HP will in addition to conducting a performance testing within 1 year of startup, also have to conduct subsequent performance testing every 8,760 hours or 3 years (whichever comes first) thereafter.

F. Streamlined Compliance Requirements

Comment: Commenters asserted that the proposed rule is complex partly due to having a combined rulemaking. One commenter stated that the proposed rule is too complex for most small oil and gas operators to be able to fully understand and evaluate. The commenter also believed that the proposed rule requires a person with significant knowledge and experience with CAA rules and requirements to understand it. One commenter stated that the proposed rulemaking added much complexity to the 2004 rulemaking for stationary RICE greater than 500 HP located at major sources, as it combined the adoption of a new NSPS, the expansion of the 2004 requirements to smaller sources, and the addition of the section 112(k) of the CAA requirements covering HAP emissions at area sources. The commenter believed that this complex interweaving of the area source requirements with the major source requirements make the rule very difficult to follow relative to area sources. This commenter recommended that EPA separate the major source from the area source requirements and suggested that one way of doing this would be to establish two separate subparts in 40 CFR part 63 for stationary RICE; one to cover area sources and another to cover major sources. According to the commenter, this approach would simplify and clarify the rule for small businesses and the various State and local agencies. In addition, the commenter recommended that EPA avoid similar interweaving of requirements, and strive to create simpler, easier to understand area source rulemakings under section 112(k) of the CAA in the future.

Two commenters were concerned that there are conflicting or duplicate requirements between the proposed NSPS, existing nonroad regulations, the RICE NESHAP, and the currently proposed NESHAP. Specifically, the existing RICE NESHAP requirements for formaldehyde and the currently proposed emission limit for non-methane hydrocarbons (NMHC) to control HAP are duplicative and may lead to conflicting or impractical reduction requirements for some engines, or may be technically infeasible, the commenters said. Other commenters noted that stationary natural gas engines greater than 500 HP located at a major source are required to comply with 40 CFR part 63, subpart ZZZZ, and the NSPS NMHC limits. According to one commenter, it also creates confusion, since it may not be technically feasible to meet the various standards required in the NSPS and the NESHAP simultaneously. Three commenters recommended that all engines greater than 500 HP and all 4SLB engines greater than 250 HP located at major sources be exempt from meeting the NMHC NSPS standards. The emissions controls needed to meet the NESHAP standards applicable to those engines are sufficient to reduce HAP and other HC emissions. Elimination of the NMHC standard for that group of engines in the NSPS will simplify the rules, eliminate confusing, redundant, and possibly conflicting

requirements, and will relieve owners/operators from unnecessary testing and monitoring requirements, according to commenters.

Response: EPA believes that the approach taken to have a combined rulemaking is more effective than having separate rules for the same types of facilities and will help reduce burden and EPA also believes that having a combined rulemaking, as well as regulations that refer to one another and are promulgated concurrently, actually simplifies compliance for affected sources. Commenters are reminded that Congress requires EPA to promulgate standards under both sections 111 and 112 of the CAA, which requires that owners and operators of sources covered under both sections are required to meet standards under both sections. However, EPA has made a major simplification in the final rule and has included a provision in section 63.6590 of the final NESHAP that owners/operators of new and reconstructed engines less than 500 HP located at major sources (except new and reconstructed 4SLB engines between 250 and 500 HP) and engines located at area sources will be in compliance with the NESHAP if they are in compliance with the NSPS. This approach is substantively the same as the approach in the notice of proposed rulemaking, at least in terms of emission requirements, but EPA believes this approach more clearly streamlines and simplifies compliance and greatly reduces the complexity that may be associated with demonstrating compliance for owners/operators and makes the rule easy to understand for all parties affected, including small business owners and State and local agencies. Additionally, for the most part the only thing required from small engine owners/operators is that they purchase a certified engine, which EPA believes will be available for most, if not all, of the smaller engines, and operate the engine according to the manufacturer's specifications. EPA further notes that even for non-certified engines, requirements are reduced, especially for smaller engines. However, EPA appreciates the commenters' concerns and has made changes to the proposed rule that will further help affected parties understand and evaluate the requirements, as discussed above.

EPA understands the commenters' concerns and agrees that there may be some duplication in the proposed rule and has taken steps in the final rule to simplify the compliance process for owners/operators by removing potential duplicative and/or conflicting requirements. Specifically, EPA realizes that certain engines will be subject to two sets of emission standards and regulations. New engines over 500 HP located at major sources would be subject to the NESHAP as well as the NSPS. Stationary 4SLB engines between 250 and 500 HP located at major sources would also be subject to the NESHAP and NSPS. EPA does not agree with the commenters that recommend that EPA exempt all engines greater than 500 HP and 4SLB above 250 HP at major sources from meeting the NSPS NMHC (now VOC) standard. These stationary engines will be required to comply with both regulations. One regulation addresses HAP emissions and the other regulation addresses criteria pollutants. The commenters provide no data or analysis indicating that it would be infeasible to meet both regulations, and EPA has shown that the standards under both regulations are feasible.

For the current 40 CFR part 63, subpart ZZZZ, EPA did not find that there is a good relationship between CO emission concentration or CO emission reductions and HAP emission concentrations or HAP emission reductions from rich burn engines equipped with NSCR. Therefore, in that rule, EPA could not use CO as a surrogate for HAP for rich burn engines. For that reason, EPA cannot exempt stationary rich burn engines from either regulation, and rich burn engines greater than 500 HP located at major sources have to comply with the formaldehyde emission standard in the RICE NESHAP (percent reduction or concentration limit) and the NO_X, CO, and VOC emission standards in the SI NSPS.

However, for SI lean burn engines, under the existing RICE NESHAP, EPA established a good relationship between CO emission reductions and HAP emission reductions from 4SLB engines with oxidation catalyst systems. Therefore, EPA concluded that CO emission reductions could serve as a surrogate for HAP emission reductions for SI lean burn engines with oxidation catalysts. Since the existing RICE NESHAP contains emission standards for CO and formaldehyde that are based on the application of oxidation catalysts, it makes sense to exempt these engines from the CO emission standard under the SI NSPS, which would be less stringent than the NESHAP CO standard. For this group of engines, and for 4SLB engines between 250 and 500 HP located at major sources, EPA believes it is more appropriate and reasonable to exempt the engines from the CO standard in the NSPS, since that is the same pollutant that they are testing for in the NESHAP, rather than the VOC standard. Based on comments received and other information analyzed post-proposal, EPA believes that CO is a more appropriate surrogate for formaldehyde than VOC for SI lean burn engines and EPA does not believe VOC should be used as a surrogate for HAP. EPA recognizes that it proposed exempting 4SLB engines between 250 and 500 HP at major sources from the NSPS NMHC standard, but based on new information comments submitted by EUROMOT (EPA–HQ–OAR–2005–0030–0039), EPA now believes that CO is more appropriate and consistent with the NESHAP for 4SLB engines. Therefore, SI lean burn engines greater than or equal to 250 HP located at major sources that comply with the RICE NESHAP only have to comply with the NO_X and VOC standard in the SI NSPS. EPA has included this provision in Table 1 to the final NSPS.

VI. Summary of Environmental, Energy and Economic Impacts

A. What are the air quality impacts?

The final rule is estimated to reduce NO_X emissions from stationary SI ICE by an estimated 77,000 tons per year (tpy), CO emissions by about 45,000 tpy, VOC emissions by about 2,000 tpy, and HAP emissions by approximately 800 tpy in the year 2015. Of the 800 tpy of HAP reduced in 2015, it is expected that about 86 tpy will be the result of requirements under the RICE NESHAP. The final rule is estimated to reduce NO_X emissions by 84,000 tpy, CO emissions by 49,000 tpy, VOC emissions by 2,400 tpy, and HAP emissions by 900 tpy in the year 2020. Of the 900 tpy of HAP reduced in 2020, it is expected that about 100 tpy will be the result of requirements under the RICE NESHAP. The final rule is estimated to reduce NO_X emissions by 99,000 tpy, CO emissions by 56,000 tpy, VOC emissions by 3,000 tpy, and HAP emissions by 1,000 tpy in the year 2030. Of the 1,000 tpy of HAP reduced in 2030, it is expected that about 120 tpy will be the result of requirements under the RICE NESHAP.

EPA estimates that a total of about 150,000 stationary SI engines will be affected by the final rule by the year 2015. A total of 433,000 stationary SI engines will be affected by the year 2030. An estimated 623,000 stationary CI engines will be affected by the final rule by the year 2015. However, stationary CI engines affected by the final rule would also be subject to the CI NSPS. Further information regarding the estimated reductions of the final rule can be found in the memorandum entitled "Cost Impacts and Emission Reductions Associated with Proposed NSPS for Stationary SI ICE and

NESHAP for Stationary RICE," which is available in the docket.

B. What are the cost impacts?

The total national capital cost for the final rule is estimated to be approximately $44 million in the year 2015, with a total national annual cost of $19 million in the year 2015. Total national capital cost for the RICE NESHAP portion of the final rule are $3 million in 2015 with a total annual cost of also $3 million in 2015. In the year 2020, the total national capital and annual costs for the final rule are estimated to be $47 million and $20 million, respectively. Total national capital cost for the RICE NESHAP portion of the final rule are $3.5 million in 2020 with a total annual cost of $3.5 million in 2020. In the year 2030, the total national capital and annual costs for the final rule are estimated to be $54 million and $22 million, respectively. Total national capital cost for the RICE NESHAP portion of the final rule are $4.2 million in 2030 with a total annual cost of $4.3 million in 2030.

C. What are the benefit estimates?

EPA estimates the monetized benefits of this final rule to be about $220 million (2005$). This estimate of benefits reflects the use of the Pope *et al.* (2002) $PM_{2.5}$ mortality estimate. EPA recognizes the uncertainty associated with this estimate and readers may refer to the benefits chapter of the Regulatory Impacts Analysis for a discussion of the range of benefits estimated for this rule. To estimate the human health benefits of NO_X emission reductions from stationary SI engines, EPA followed an approach and methodology described in the Technical Support Document (TSD) accompanying EPA's 2007 benefits analysis of the proposed changes to the National Ambient Air Quality Standards for Ozone. In this analysis, EPA applied dollar per ton benefit transfer coefficients. These benefit per ton estimates relate a one-ton reduction in a given $PM_{2.5}$ precursor, such as NO_X emitted by stationary sources, to an estimate of the total monetized human health benefits of reduced exposure to $PM_{2.5}$. EPA chose these transfer coefficients as the basis for estimating the benefits from emission reductions of these two pollutants because the coefficients were derived for sources that share many of the same key attributes as those covered here. These elements include the stack height and the pollutant affected-NO_X. Thus EPA believes that it can generate a reasonable estimate of benefits for this final rule using a benefits transfer approach. Specifically, these estimates are based on application of the benefits scaling approach derived from the benefits analyses completed for these rulemakings. Readers interested in the methodology followed to generate these estimates may consult the Technical Support Document supporting the Proposed Ozone NAAQS RIA.[1] A summary of the benefits estimates is in Table 5 of this preamble.

TABLE 5.—ESTIMATE OF MONETIZED BENEFITS BY 2015 ($2005) [a]

$ Benefits/ton	Amount of NO_X emissions reduced (tons)	Monetized benefits (millions of 2005$) [b]
$2,800	77,362	$220

[a] The results are presented assuming a discount rate of three percent.
[b] Estimate rounded to two significant figures.

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 American Cancer Society cohort (ACS) (Pope, C.A. III, *et al.*, "Lung Cancer, Cardiopulmonary Mortality, and Long-Term Exposure to Fine Particulate Air Pollution," JAMA, 2002).

Since the publication of Clean Air Interstate Rulemaking (CAIR), the EPA's Office of Air and Radiation has adopted a different format for its benefits analysis in which characterization of the uncertainty in the concentration response function is integrated into the main benefits analysis. The PM NAAQS RIA analysis prepared last year provides an indication of the sensitivity of our results to the use of alternative concentration response functions, including those derived from the recently completed expert elicitation study. Specifically, compared to the final PM NAAQS estimate of the mean mortality from the ACS cohort, the expert-based premature mortality incidence ranged from 50 percent of the mean ACS estimate to more than five times the size of the ACS mean estimate. The Agency intends to consider using information to update our benefits estimates as part of an approach similar to that used in the PM NAAQS Regulatory Impact Analysis (RIA) in the benefits analyses for future rulemakings.

EPA estimates the annualized benefits of this rulemaking (the NSPS and NESHAP together) to be about $220 million (2005$) and annualized costs to be $22 million (2005$). Thus, benefits exceed cost by about to $200 million in 2015. EPA believes that the benefits are likely to exceed the costs by a significant margin under this rulemaking even when taking into account uncertainties in the cost and benefit estimates. For more information, please refer to the RIA for this final rule that is available in the docket.

D. What are the economic impacts?

The impacts to producers and consumers affected by this final rule are higher product prices and outputs. Prices for affected engines that are larger than 175 HP may increase from 5 to 7 percent, and prices for engines smaller than 175 HP may increase by 17 to 33 percent. Production of affected engines, however, should only fall by between 0.5 and 3.3 percent since previous analyses by EPA of engine markets done for the Final Nonroad Diesel Engine Rule suggest a small reaction in output due to a large price increase. Hence, the overall economic impact on affected industries should be small.

E. What are the non-air health, environmental and energy impacts?

EPA does not anticipate any significant non-air health, environmental or energy impacts as a result of the final rule.

VII. 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 affect 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.

B. Paperwork Reduction Act

The information collection requirements in this final rule 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 requirements are based on notification, recordkeeping, and reporting requirements in the NSPS General Provisions (40 CFR part 60, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically

[1] Technical Support Document: Calculating Benefit per-Ton Estimates. EPA–HQ–OAR–2006–0834.

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 Agency policies set forth in 40 CFR part 2, subpart B.

This final rule will require notifications from certain engines and compliance reports. The recordkeeping requirements require only the specific information needed to determine compliance.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of this final rule) is estimated to be 132,164 labor hours per year at a total annual cost of $17,995,722. This estimate includes a one-time notification for engines greater than 500 HP that are non-certified, engine certification, engine performance testing, and recordkeeping. There are no capital/start-up costs associated with the monitoring requirements over the 3-year period of the ICR. The operation and maintenance costs for the monitoring requirements over the 3-year period of the ICR are estimated to be $8,498,888 per year.

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 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. In addition, EPA is amending the table in 40 CFR part 9 of currently approved OMB control numbers for various regulations to list the regulatory citations for the information 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 the purposes of assessing the impacts of this final rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

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 is expected to affect 21 ultimate parent businesses that are manufacturers of affected SI engines. Five of the parent businesses are small according to the SBA small business size standard. One of these five firms would have an annualized cost of more than one percent of sales associated with meeting the requirements; the estimated cost is about five percent of the annual sales for this small firm. In addition, for the industries in which small firms are found that may be affected by this final rule, either by purchasing a compliant SI engine or by performing the required testing, the estimated cost of this rule is 0.10 percent of sales or less. Also, no other adverse impacts are expected to these affected small businesses.

For more information on the small entity impacts associated with the final rule, please refer to the Economic Impact and Small Business Analyses in the public docket. These analyses can be found in the Regulatory Impact Analysis for this final rule.

Although this final rule 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. When developing the revised standards, EPA took special steps to ensure that the burdens imposed on small entities were minimal. EPA conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting.

D. Unfunded Mandates Reform Act of 1995

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 by State, local, and tribal governments, in the aggregate, or by 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 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. Thus, this final 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.

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. This final rule primarily affects private industry, and does not impose significant economic costs on State or local governments. Thus, Executive Order 13132 does not apply to the final rule. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on the proposed rule from State and local officials.

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. Thus, Executive Order 13175 does not apply to the final rule.

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

Executive Order 13045 "Protection of Children from Environmental Health 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 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. This final rule is not subject to Executive Order 13045 because it is 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 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. EPA has prepared an analysis of energy impacts that explains this conclusion as follows.

The increase in petroleum product output, which includes increases in fuel production, is estimated at less than 0.03 percent, or 11.1 trillion BTUs as based on 2007 Annual Energy Outlook data provided by the U.S. Energy Information Administration. The reduction in coal production is zero since no coal-fired units will be affected by the requirements of the final rule. The reduction in electricity output is estimated at 0.10 percent, or about 15.1 trillion BTUs per year based on 2007 U.S. electricity production nationwide. Production of natural gas is expected to decrease by 13.83 trillion BTU, a decrease of 0.07 percent from 2007 U.S. production levels. The maximum of all energy price increases, which include increases in natural gas prices as well as those for petroleum products, and electricity, is estimated to be 0.10 percent nationwide. Energy distribution costs may increase by roughly no more than the same amount as electricity rates. EPA expects that there will be no discernable impact on the import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies. The increase in cost of energy production should be minimal given the very small increases in energy prices and outputs shown above. All of the estimates presented above account for some pass-through of costs to consumers as well as the direct cost impact to producers. For more information on these estimated energy effects, please refer to the economic impact analysis for the final rule. This analysis is available in the public docket.

Therefore, EPA concludes that this rule when implemented will not have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

As noted in the proposed rule, Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113, Section 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. The 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 does not use available and applicable VCS. These rules involve technical standards. The EPA cites the following standards: EPA Methods 1, 1A, 2, 3, 3A, 3B, 4, 7E, 10, 18, 19, 25A, 320, and 323 (40 CFR part 60, appendix A); and American Society of Testing and Materials (ASTM) methods ASTM D6348–03 and ASTM D6522–00 (2005).

Consistent with the NTTAA, EPA conducted searches to identify voluntary potentially applicable consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 1A, 19, 320, and 323. The search and review results are in the docket for these rules.

The search identified two voluntary consensus standards as acceptable alternatives to EPA Methods. In addition, the standards, ASTM D6348–03 and ASTM D6522–00 (2005) cited in these rules are also VCS.

The standard ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," is cited in this rule for its manual method for measuring the oxygen content of the exhaust gas. This part of ASME PTC 19.10–1981 is an acceptable alternative to EPA Method 3B.

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 total nonmethane organic.

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 GC/MS. While offering advantages over the traditional Method 18, the ASTM method does allow some less stringent criteria for accepting GC/MS results than required by Method 18. Therefore, ASTM D6420–99 is a suitable alternative to Method 18 only where:

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

(2) The target concentration is between 150 ppbv 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 Method 18 as a gas chromatography (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 13 other voluntary consensus standards. The EPA determined that these 13 standards identified for measuring emissions of the HAP or surrogates subject to emission standards in these rules were impractical alternatives to EPA test methods for the purposes of these rules. Therefore, EPA does not intend to adopt these standards for this purpose. The reasons for the determinations for the 13 methods are discussed in the dockets to the rules.

Under 63.7(f) and 63.8(f) of subpart A of the General Provisions to part 63, 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 addition, EPA Method 301 describes procedures any source may use to establish the equivalency of alternatives to any EPA reference method.

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 rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This rule promulgates new source performance standards and national emission standards for hazardous air pollutants.

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 final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective on March 18, 2008.

List of Subjects

40 CFR Part 60

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

40 CFR Part 63

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

40 CFR Part 85

Imports, Labeling, Motor vehicle pollution, Reporting and recordkeeping requirements, Research, Warranties.

40 CFR Part 90

Administrative practice and procedure, Air pollution control.

40 CFR Part 1048

Administrative practice and procedure, Air pollution control.

40 CFR Part 1065

Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements, Research.

40 CFR Part 1068

Administrative practice and procedure, Imports, Motor vehicle pollution, Penalties, Reporting and recordkeeping requirements, Warranties.

Dated: December 20, 2007.

Stephen L. Johnson,

Administrator.

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

PART 60—[AMENDED]

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

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

Subpart A—[Amended]

■ 2. Section 60.17 is amended as follows:

■ a. By revising paragraph (a)(82);

■ b. By redesignating paragraphs (a)(85) through (a)(90) as paragraphs (a)(87) through (a)(92);

■ c. By redesignating paragraph (a)(84) as (a)(85);

■ d. By adding new paragraph (a)(84);

■ e. By adding new paragraph (a)(86);

■ f. By revising paragraph (h)(4); and
■ g. By adding paragraph (n).

The revisions and additions read as follows:

§ 60.17 Incorporation by Reference

* * * * *

(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 and table 2 of subpart JJJJ of this part.

* * * * *

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

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(86) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for table 2 of subpart JJJJ of this part.

* * * * *

(h) * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], IBR approved for 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.

* * * * *

(n) This material is available for purchase from IHS Inc., 15 Inverness Way East, Englewood, CO 80112.

(1) International Organization for Standards 8178–4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—Part 4: Test Cycles for Different Engine Applications, IBR approved for § 60.4241(b).

(2) [Reserved]

Subpart JJJJ—[Amended]

■ 3. Part 60 is amended by adding subpart JJJJ to read as follows:

Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

Sec.

What This Subpart Covers

60.4230 Am I subject to this subpart?

Emission Standards for Manufacturers

60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines?

60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?

Emission Standards for Owners and Operators

60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?

Other Requirements for Owners and Operators

60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?

60.4236 What is the deadline for importing or installing stationary SI ICE produced in the previous model year?

60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

Compliance Requirements for Manufacturers

60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP)?

60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline?

60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG?

60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program?

60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines?

Compliance Requirements for Owners and Operators

60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

Testing Requirements for Owners and Operators

60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

Notification, Reports, and Records for Owners and Operators

60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

General Provisions

60.4246 What parts of the General Provisions apply to me?

Mobile Source Provisions

60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines?

Definitions

60.4248 What definitions apply to this subpart?

Tables to Subpart JJJJ of Part 60

Table 1 to Subpart JJJJ of Part 60—NO_X, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (except gasoline and rich burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP.

Table 2 to Subpart JJJJ of Part 60—Requirements for Performance Tests.

Table 3 to Subpart JJJJ of Part 60—Applicability of General Provisions to Subpart JJJJ.

Table 4 to Subpart JJJJ of Part 60—Applicability of Mobile Source Provisions for Manufacturers Participating in the Voluntary Certification Program and Certifying Stationary SI ICE to Emission Standards in Table 1 of Subpart JJJJ.

What This Subpart Covers

§ 60.4230 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (5) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary SI ICE with a maximum engine power less than or equal to 19 kilowatt (KW) (25 horsepower (HP)) that are manufactured on or after July 1, 2008.

(2) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline fueled or that are rich burn engines fueled by liquefied petroleum gas (LPG), where the date of manufacture is:

(i) On or after July 1, 2008; or

(ii) On or after January 1, 2009, for emergency engines.

(3) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are not gasoline fueled and are not rich burn

engines fueled by LPG, where the manufacturer participates in the voluntary manufacturer certification program described in this subpart and where the date of manufacture is:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) On or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) On or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) On or after January 1, 2009, for emergency engines.

(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

(5) Owners and operators of stationary SI ICE that commence modification or reconstruction after June 12, 2006.

(b) The provisions of this subpart are not applicable to stationary SI ICE being tested at an engine test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(d) For the purposes of this subpart, stationary SI ICE using alcohol-based fuels are considered gasoline engines.

(e) Stationary SI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR parts 90 and 1048, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(f) Owners and operators of facilities with internal combustion engines that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

Emission Standards for Manufacturers

§ 60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines?

(a) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90.

(b) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cubic centimeters (cc) to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90.

(c) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90.

(d) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) under the voluntary manufacturer certification program described in this subpart must certify those engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers who choose to certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP, must certify those engines to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards for new nonroad SI engines in 40 CFR part 90. For stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP)

(except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) manufactured prior to January 1, 2011, manufacturers may choose to certify these engines to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP.

(e) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) under the voluntary manufacturer certification program described in this subpart must certify those engines to the emission standards in Table 1 to this subpart. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) that are lean burn engines that use LPG to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. For stationary SI ICE with a maximum engine power greater than or equal to 100 HP (75 KW) and less than 500 HP (373 KW) manufactured prior to January 1, 2011, and for stationary SI ICE with a maximum engine power greater than or equal to 500 HP (373 KW) manufactured prior to July 1, 2010, manufacturers may choose to certify these engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048 applicable to engines that are not severe duty engines.

§ 60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?

Engines manufactured by stationary SI internal combustion engine manufacturers must meet the emission standards as required in § 60.4231 during the certified emissions life of the engines.

Emission Standards for Owners and Operators

§ 60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

(a) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008, must comply with the emission standards in § 60.4231(a) for their stationary SI ICE.

(b) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in § 60.4230(a)(4) that use gasoline must comply with the emission standards in § 60.4231(b) for their stationary SI ICE.

(c) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in § 60.4230(a)(4) that are rich burn engines that use LPG must comply with the emission standards in § 60.4231(c) for their stationary SI ICE.

(d) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards for field testing in 40 CFR 1048.101(c) for their non-emergency stationary SI ICE and with the emission standards in Table 1 to this subpart for their emergency stationary SI ICE. Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) manufactured prior to January 1, 2011, that were certified to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP, may optionally choose to meet those standards.

(e) Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 HP (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in Table 1 to this subpart, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.

(f) Owners and operators of any modified or reconstructed stationary SI ICE subject to this subpart must meet the requirements as specified in paragraphs (f)(1) through (5) of this section.

(1) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (a) of this section.

(2) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that use gasoline engines, that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (b) of this section.

(3) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are rich burn engines that use LPG, that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (c) of this section.

(4) Owners and operators of stationary SI natural gas and lean burn LPG engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (d) or (e) of this section, except that such owners and operators of non-emergency engines and emergency engines greater than or equal to 130 HP must meet a nitrogen oxides (NO_X) emission standard of 3.0 grams per HP-hour (g/HP-hr), a CO emission standard of 4.0 g/HP-hr (5.0 g/HP-hr for non-emergency engines less than 100 HP), and a volatile organic compounds (VOC) emission standard of 1.0 g/HP-hr, or a NO_X emission standard of 250 ppmvd at 15 percent oxygen (O_2), a CO emission standard 540 ppmvd at 15 percent O_2 (675 ppmvd at 15 percent O_2 for non-emergency engines less than 100 HP), and a VOC emission standard of 86 ppmvd at 15 percent O_2, where the date of manufacture of the engine is:

(i) Prior to July 1, 2007, for non-emergency engines with a maximum engine power greater than or equal to 500 HP;

(ii) Prior to July 1, 2008, for non-emergency engines with a maximum engine power less than 500 HP;

(iii) Prior to January 1, 2009, for emergency engines.

(5) Owners and operators of stationary SI landfill/digester gas ICE engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (e) of this section for stationary landfill/digester gas engines.

(g) Owners and operators of stationary SI wellhead gas ICE engines may petition the Administrator for approval on a case-by-case basis to meet emission standards no less stringent than the emission standards that apply to

stationary emergency SI engines greater than 25 HP and less than 130 HP due to the presence of high sulfur levels in the fuel, as specified in Table 1 to this subpart. The request must, at a minimum, demonstrate that the fuel has high sulfur levels that prevent the use of aftertreatment controls and also that the owner has reasonably made all attempts possible to obtain an engine that will meet the standards without the use of aftertreatment controls. The petition must request the most stringent standards reasonably applicable to the engine using the fuel.

(h) Owners and operators of stationary SI ICE that are required to meet standards that reference 40 CFR 1048.101 must, if testing their engines in use, meet the standards in that section applicable to field testing, except as indicated in paragraph (e) of this section.

§ 60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in § 60.4233 over the entire life of the engine.

Other Requirements for Owners and Operators

§ 60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?

Owners and operators of stationary SI ICE subject to this subpart that use gasoline must use gasoline that meets the per gallon sulfur limit in 40 CFR 80.195.

§ 60.4236 What is the deadline for importing or installing stationary SI ICE produced in the previous model year?

(a) After July 1, 2010, owners and operators may not install stationary SI ICE with a maximum engine power of less than 500 HP that do not meet the applicable requirements in § 60.4233.

(b) After July 1, 2009, owners and operators may not install stationary SI ICE with a maximum engine power of greater than or equal to 500 HP that do not meet the applicable requirements in § 60.4233, except that lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP that do not meet the applicable requirements in § 60.4233 may not be installed after January 1, 2010.

(c) For emergency stationary SI ICE with a maximum engine power of greater than 19 KW (25 HP), owners and operators may not install engines that do not meet the applicable requirements in § 60.4233 after January 1, 2011.

(d) In addition to the requirements specified in §§ 60.4231 and 60.4233, it is prohibited to import stationary SI ICE less than or equal to 19 KW (25 HP), stationary rich burn LPG SI ICE, and stationary gasoline SI ICE that do not meet the applicable requirements specified in paragraphs (a), (b), and (c) of this section, after the date specified in paragraph (a), (b), and (c) of this section.

(e) The requirements of this section do not apply to owners and operators of stationary SI ICE that have been modified or reconstructed, and they do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

(a) Starting on July 1, 2010, if the emergency stationary SI internal combustion engine that is greater than or equal to 500 HP that was built on or after July 1, 2010, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.

(b) Starting on January 1, 2011, if the emergency stationary SI internal combustion engine that is greater than or equal to 130 HP and less than 500 HP that was built on or after January 1, 2011, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.

(c) If you are an owner or operator of an emergency stationary SI internal combustion engine that is less than 130 HP, was built on or after July 1, 2008, and does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter upon startup of your emergency engine.

Compliance Requirements for Manufacturers

§ 60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP)?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(a) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, and must test their engines as specified in that part.

§ 60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(b) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, and must test their engines as specified in that part.

§ 60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(c) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90, and manufacturers of emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, and must test their engines as specified in that part.

§ 60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program?

(a) Manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and

are not rich burn engines that use LPG can choose to certify their engines to the emission standards in § 60.4231(d) or (e), as applicable, under the voluntary certification program described in this subpart. Manufacturers who certify their engines under the voluntary certification program must meet the requirements as specified in paragraphs (b) through (g) of this section. In addition, manufacturers of stationary SI internal combustion engines who choose to certify their engines under the voluntary certification program, must also meet the requirements as specified in § 60.4247.

(b) Manufacturers of engines other than those certified to standards in 40 CFR part 90 must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must follow the same test procedures that apply to large SI nonroad engines under 40 CFR part 1048, but must use the D–1 cycle of International Organization of Standardization 8178–4: 1996(E) (incorporated by reference, see 40 CFR 60.17) or the test cycle requirements specified in Table 5 to 40 CFR 1048.505, except that Table 5 of 40 CFR 1048.505 applies to high load engines only. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90, and manufacturers of emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, and must test their engines as specified in that part.

(c) Certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, is voluntary, but manufacturers who decide to certify are subject to all of the requirements indicated in this subpart with regard to the engines included in their certification. Manufacturers must clearly label their stationary SI engines as certified or non-certified engines.

(d) Manufacturers of natural gas fired stationary SI ICE who conduct voluntary certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the definition of pipeline-quality natural gas. The fuel used for certifying stationary SI natural gas engines must meet the definition of pipeline-quality natural gas as described in § 60.4248. In addition, the manufacturer must provide information to the owner and operator of the certified stationary SI engine including the specifications of the pipeline-quality natural gas to which the engine is certified and what adjustments the owner or operator must make to the engine when installed in the field to ensure compliance with the emission standards.

(e) Manufacturers of stationary SI ICE that are lean burn engines fueled by LPG who conduct voluntary certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the specifications in 40 CFR 1065.720.

(f) Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in § 60.4231(d) or (e), as applicable, when operating on that fuel. The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition. The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on gaseous fuels with different quality than the fuel that it was certified to.

(g) A stationary SI engine manufacturer may certify an engine family solely to the standards applicable to landfill/digester gas engines as specified in § 60.4231(d) or (e), as applicable, but must certify their engines for operation using landfill/digester gas and must add a permanent label stating that the engine is for use only in landfill/digester gas applications. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(h) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

§ 60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines?

(a) Stationary SI internal combustion engine manufacturers must meet the provisions of 40 CFR part 90 or 40 CFR part 1048, as applicable, as well as 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1048, except that engines certified pursuant to the voluntary certification procedures in § 60.4241 are subject only to the provisions indicated in § 60.4247 and are permitted to provide instructions to owners and operators allowing for deviations from certified configurations, if such deviations are consistent with the provisions of paragraphs § 60.4241(c) through (f). Labels on engines certified to 40 CFR part 1048 must refer to stationary engines, rather than or in addition to nonroad engines, as appropriate.

(b) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR part 90 or 40 CFR part 1048 for that model year may certify any such family that contains both nonroad and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(c) Manufacturers of engine families certified to 40 CFR part 1048 may meet the labeling requirements referred to in paragraph (a) of this section for stationary SI ICE by either adding a separate label containing the information required in paragraph (a) of this section or by adding the words "and stationary" after the word "nonroad" to the label.

(d) For all engines manufactured on or after January 1, 2011, and for all engines with a maximum engine power greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, a stationary SI engine manufacturer that certifies an engine family solely to the standards applicable to emergency engines must add a permanent label stating that the engines in that family are for emergency use only. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(e) All stationary SI engines subject to mandatory certification that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230. Stationary SI engines subject to standards in 40 CFR part 90 may use the provisions in 40 CFR 90.909. Manufacturers of stationary engines with a maximum engine power greater than 25 HP that are not certified to standards and other requirements under 40 CFR part 1048 are subject to the

labeling provisions of 40 CFR 1048.20 pertaining to excluded stationary engines.

Compliance Requirements for Owners and Operators

§ 60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

(a) If you are an owner or operator of a stationary SI internal combustion engine that is manufactured after July 1, 2008, and must comply with the emission standards specified in § 60.4233(a) through (c), you must comply by purchasing an engine certified to the emission standards in § 60.4231(a) through (c), as applicable, for the same engine class and maximum engine power. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance. In addition, you must meet one of the requirements specified in (a)(1) and (2) of this section.

(1) If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator.

(2) If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.

(i) If you are an owner or operator of a stationary SI internal combustion engine less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions, but no performance testing is required if you are an owner or operator.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup to demonstrate compliance.

(iii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in § 60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.

(1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.

(2) Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in § 60.4233(d) or (e) and according to the requirements specified in § 60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.

(i) If you are an owner or operator of a stationary SI internal combustion engine greater than 25 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(c) If you are an owner or operator of a stationary SI internal combustion engine that must comply with the emission standards specified in § 60.4233(f), you must demonstrate compliance according paragraph (b)(2)(i) or (ii) of this section, except that if you comply according to paragraph (b)(2)(i) of this section, you demonstrate that your non-certified engine complies with the emission standards specified in § 60.4233(f).

(d) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Emergency stationary ICE may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as permitted in this section, is prohibited.

(e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to

demonstrate compliance with the emission standards of § 60.4233.

(f) If you are an owner or operator of a stationary SI internal combustion engine that is less than or equal to 500 HP and you purchase a non-certified engine or you do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, you are required to perform initial performance testing as indicated in this section, but you are not required to conduct subsequent performance testing unless the stationary engine is rebuilt or undergoes major repair or maintenance. A rebuilt stationary SI ICE means an engine that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(g) It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.

(h) If you are an owner/operator of an stationary SI internal combustion engine with maximum engine power greater than or equal to 500 HP that is manufactured after July 1, 2007 and before July 1, 2008, and must comply with the emission standards specified in sections 60.4233(b) or (c), you must comply by one of the methods specified in paragraphs (h)(1) through (h)(4) of this section.

(1) Purchasing an engine certified according to 40 CFR part 1048. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

Testing Requirements for Owners and Operators

§ 60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in § 60.8 and under the specific conditions that are specified by Table 2 to this subpart.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c). If your stationary SI internal combustion engine is non-operational, you do not need to startup the engine solely to conduct a performance test; however, you must conduct the performance test immediately upon startup of the engine.

(c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(d) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 1 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{HP-hr} \quad \text{(Eq. 1)}$$

Where:

ER = Emission rate of NO_X in g/HP-hr.

C_d = Measured NO_X concentration in parts per million by volume (ppmv).

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

(e) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of this section:

$$ER = \frac{C_d \times 1.164 \times 10^{-3} \times Q \times T}{HP-hr} \quad \text{(Eq. 2)}$$

Where:

ER = Emission rate of CO in g/HP-hr.

C_d = Measured CO concentration in ppmv.

1.164×10^{-3} = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(f) For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of this section:

$$ER = \frac{C_d \times 1.833 \times 10^{-3} \times Q \times T}{HP-hr} \quad \text{(Eq. 3)}$$

Where:

ER = Emission rate of VOC in g/HP-hr.

C_d = VOC concentration measured as propane in ppmv.

1.833×10^{-3} = Conversion constant for ppm VOC measured as propane, to grams per

standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(g) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{Mi}}{C_{Ai}} \qquad \text{(Eq. 4)}$$

Where:

RF_i = Response factor of compound i when measured with EPA Method 25A.

C_{Mi} = Measured concentration of compound i in ppmv as carbon.

C_{Ai} = True concentration of compound i in ppmv as carbon.

$$C_{icorr} = RF_i \times C_{imeas} \qquad \text{(Eq. 5)}$$

Where:

$C_{i\ corr}$ = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

$C_{i\ meas}$ = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{Peq} = 0.6098 \times C_{icorr} \qquad \text{(Eq. 6)}$$

Where:

C_{Peq} = Concentration of compound i in mg of propane equivalent per DSCM.

Notification, Reports, and Records for Owners and Operators

§ 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

(a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 90 and 1048.

(4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to § 60.4243(a)(2), documentation that the engine meets the emission standards.

(b) For all stationary SI emergency ICE greater than or equal to 500 HP manufactured on or after July 1, 2010, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than or equal to 130 HP and less than 500 HP manufactured on or after July 1, 2011 that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

(c) Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in § 60.4231 must submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (c)(1) through (5) of this section.

(1) Name and address of the owner or operator;

(2) The address of the affected source;

(3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(4) Emission control equipment; and

(5) Fuel used.

(d) Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in § 60.4244 within 60 days after the test has been completed.

General Provisions

§ 60.4246 What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

Mobile Source Provisions

§ 60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines?

(a) Manufacturers certifying to emission standards in 40 CFR part 90, including manufacturers certifying emergency engines below 130 HP, must meet the provisions of 40 CFR part 90.

(b) Manufacturers certifying to emission standards in 40 CFR part 1048 must meet the provisions of 40 CFR part 1048. Manufacturers of stationary SI internal combustion engines that are less than 100 HP participating in the voluntary certification program must meet the requirements in Table 4 to this subpart.

(c) For manufacturers of stationary SI internal combustion engines participating in the voluntary certification program and certifying engines to Table 1 to this subpart, Table 4 to this subpart shows which parts of the mobile source provisions in 40 CFR parts 1048, 1065, and 1068 apply to you. Compliance with the deterioration factor provisions under 40 CFR 1048.205(n) and 1048.240 will be required for engines built new on and after January 1, 2010. Prior to January 1, 2010, manufacturers of stationary internal combustion engines participating in the voluntary certification program have the option to develop their own deterioration factors based on an engineering analysis.

Definitions

§ 60.4248 What definitions apply to this subpart?

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

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) are given in 40 CFR 90.105. The values for certified emissions life for stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) certified to 40 CFR part 1048 are

given in 40 CFR 1048.101(g). The certified emissions life for stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) certified under the voluntary manufacturer certification program of this subpart is 5,000 hours or 7 years, whichever comes first.

Certified stationary internal combustion engine means an engine that belongs to an engine family that has a certificate of conformity that complies with the emission standards and requirements in this part, or of 40 CFR part 90 or 40 CFR part 1048, as appropriate.

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide (CO_2).

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary SI ICE used for peak shaving are not considered emergency stationary ICE. Stationary ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Manufacturer has the meaning given in section 216(1) of the Clean Air Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1048.801.

Model year means either: The calendar year in which the engine was originally produced, or the annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year, and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Pipeline-quality natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline-quality natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units per standard cubic foot.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to June 12, 2006, with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to either: a gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is

not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Stationary internal combustion engine test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that test stationary ICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Subpart means 40 CFR part 60, subpart JJJJ.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

Volatile organic compounds means volatile organic compounds as defined in 40 CFR 51.100(s).

Voluntary certification program means an optional engine certification program that manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to participate in to certify their engines to the emission standards in § 60.4231(d) or (e), as applicable.

Tables to Subpart JJJJ of Part 60

TABLE 1 TO SUBPART JJJJ OF PART 60.—NO_X, CO, AND VOC EMISSION STANDARDS FOR STATIONARY NON-EMERGENCY SI ENGINES ≥100 HP (EXCEPT GASOLINE AND RICH BURN LPG), STATIONARY SI LANDFILL/DIGESTER GAS ENGINES, AND STATIONARY EMERGENCY ENGINES >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards[a]					
			g/HP-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC[d]	NO_X	CO	VOC[d]
Non-Emergency SI Natural Gas[b] and Non-Emergency SI Lean Burn LPG[b].	100≤HP<500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60
Non-Emergency SI Lean Burn Natural Gas and LPG.	500≥HP<1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500=≥HP<1,350).	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	HP≥500	7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500≥HP<1,350).	HP<500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
	HP≥500	7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas Lean Burn	500≥HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Emergency	25>HP<130	1/1/2009	[c]10	387	N/A	N/A	N/A	N/A
	HP≥130		2.0	4.0	1.0	160	540	86

[a] Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O_2.

[b] Owners and operators of new or reconstructed non-emergency lean burn SI stationary engines with a site rating of greater than or equal to 250 brake HP located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2A do not have to comply with the CO emission standards of Table 1 of this subpart.

[c] The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_X+HC.

[d] For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

TABLE 2 TO SUBPART JJJJ OF PART 60.—REQUIREMENTS FOR PERFORMANCE TESTS

[As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to § 60.4244.	a. limit the concentration of NO_X in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A or ASTM Method D6522–00(2005)[a].	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. Determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.	

TABLE 2 TO SUBPART JJJJ OF PART 60.—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

[As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load]

For each	Complying with the requirement to	You must	Using	According to the following requirements
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see § 60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for NO_X concentration.
		v. Measure NO_X at the exhaust of the stationary internal combustion engine.	(5) Method 7E of 40 CFR part 60, appendix A, Method D6522–00(2005) [a], Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see § 60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.
b. limit the concentration of CO in the stationary SI internal combustion engine exhaust.		i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3Bb of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005) [a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for CO concentration.
		iii. Determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.	
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see § 60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.
		v. Measure CO at the exhaust of the stationary internal combustion engine.	(5) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00(2005) [a], Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.
c. limit the concentration of VOC in the stationary SI internal combustion engine exhaust.		i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B [b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005) [a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for VOC concentration.
		iii. Determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.	

TABLE 2 TO SUBPART JJJJ OF PART 60.—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

[As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load]

For each	Complying with the requirement to	You must	Using	According to the following requirements
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see § 60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.
		v. Measure VOC at the exhaust of the stationary internal combustion engine.	(5) Methods 25A and 18 of 40 CFR part 60, appendix A, Method 25A with the use of a methane cutter as described in 40 CFR 1065.265, Method 18 or 40 CFR part 60, appendix A,[c d] Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see § 60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.

[a] ASTM D6522–00 is incorporated by reference; see 40 CFR 60.17. Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

[b] You may use ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses, for measuring the O_2 content of the exhaust gas as an alternative to EPA Method 3B.

[c] You may use EPA Method 18 of 40 CFR part 60, appendix A, provided that you conduct an adequate presurvey test prior to the emissions test, such as the one described in OTM 11 on EPA's Web site (*http://www.epa.gov/ttn/emc/prelim/otm11.pdf*).

[d] You may use ASTM D6420–99 (2004), Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry as an alternative to EPA Method 18 for measuring total nonmethane organic.

TABLE 3 TO SUBPART JJJJ OF PART 60.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJ

[As stated in § 60.4246, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions.	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4248.
§ 60.3	Units and abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4245.
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§ 60.9	Availability of information	Yes.	
§ 60.10	State Authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	Yes	Requirements are specified in subpart JJJJ.
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	No.	
§ 60.14	Modification	Yes.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	Yes.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements.	No.	
§ 60.19	General notification and reporting requirements.	Yes.	

TABLE 4 TO SUBPART JJJJ OF PART 60.—APPLICABILITY OF MOBILE SOURCE PROVISIONS FOR MANUFACTURERS PARTICIPATING IN THE VOLUNTARY CERTIFICATION PROGRAM AND CERTIFYING STATIONARY SI ICE TO EMISSION STANDARDS IN TABLE 1 OF SUBPART JJJJ

[As stated in § 60.4247, you must comply with the following applicable mobile source provisions if you are a manufacturer participating in the voluntary certification program and certifying stationary SI ICE to emission standards in Table 1 of Subpart JJJJ]

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 Subpart A	Overview and Applicability	Yes.	
1048 Subpart B	Emission Standards and Related Requirements.	Yes	Except for the specific sections below.
1048.101	Exhaust Emission Standards	No.	
1048.105	Evaporative Emission Standards	No.	
1048.110	Diagnosing Malfunctions	No.	
1048.140	Certifying Blue Sky Series Engines.	No.	
1048.145	Interim Provisions	No.	
1048 Subpart C	Certifying Engine Families	Yes	Except for the specific sections below.
1048.205(b)	AECD reporting	Yes.	
1048.205(c)	OBD Requirements	No.	
1048.205(n)	Deterioration Factors	Yes	Except as indicated in 60.4247(c).
1048.205(p)(1)	Deterioration Factor Discussion	Yes.	
1048.205(p)(2)	Liquid Fuels as they require	No.	
1048.240(b)(c)(d)	Deterioration Factors	Yes.	
1048 Subpart D	Testing Production-Line Engines	Yes.	
1048 Subpart E	Testing In-Use Engines	No.	
1048 Subpart F	Test Procedures	Yes.	
1065.5(a)(4)	Raw sampling (refers reader back to the specific emissions regulation for guidance).	Yes.	
1048 Subpart G	Compliance Provisions	Yes.	
1048 Subpart H	Reserved.		
1048 Subpart I	Definitions and Other Reference Information.	Yes.	
1048 Appendix I and II		Yes.	
1065 (all subparts)	Engine Testing Procedures	Yes	Except for the specific section below.
1065.715	Test Fuel Specifications for Natural Gas.	No.	
1068 (all subparts)	General Compliance Provisions for Nonroad Programs.	Yes	Except for the specific sections below.
1068.245	Hardship Provisions for Unusual Circumstances.	No.	
1068.250	Hardship Provisions for Small-Volume Manufacturers.	No.	
1068.255	Hardship Provisions for Equipment Manufacturers and Secondary Engine Manufacturers.	No.	

PART 63—[AMENDED]

■ 4. The authority citation for part 63 continues to read as follows:

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

Subpart A—[AMENDED]

■ 5. Section 63.14 is amended by revising paragraph (b)(27) and adding paragraph (b)(64) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) * * *

(27) 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,[1] IBR approved for § 63.9307(c)(2) and Table 5 to Subpart DDDDD of this part.

* * * * *

(64) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers,[1] IBR approved for Table 4 to Subpart ZZZZ of this part.

* * * * *

■ 6. Section 63.6580 is revised to read as follows:

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

■ 7. Section 63.6585 is amended by:

■ a. Revising the introductory text;

■ b. Adding paragraph (c);

■ c. Adding paragraph (d); and

■ d. Adding paragraph (e).

The revision and additions read as follows:

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

* * * * *

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

■ 8. Section 63.6590 is amended by revising paragraphs (a) and (b), and adding paragraph (c), to read as follows:

§ 63.6590 What parts of my plant does this subpart cover?

* * * * *

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraph (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(h).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions; or

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(h) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) A stationary RICE which is an existing spark ignition 4 stroke rich burn (4SRB) stationary RICE located at an area source, an existing spark ignition 4SRB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source, an existing spark ignition 2 stroke lean burn (2SLB) stationary RICE, an existing spark ignition 4 stroke lean burn (4SLB) stationary RICE, an existing compression ignition (CI) stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, does not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that is a new or reconstructed stationary RICE located at an area source, or is a new or reconstructed stationary RICE located at a major source of HAP emissions and is a spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of less than 500 brake HP, a spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of less than 250 brake HP, or a 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP, a stationary RICE with a site rating of less than or equal to 500 brake HP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP, or a compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP, must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

■ 9. Section 63.6595 is amended by revising paragraphs (a) and (b)(2) to read as follows:

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected Sources.* (1) If you have an existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the

applicable emission limitations and operating limitations no later than June 15, 2007.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b)* * *

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

* * * * *

■ 10. Section 63.6600 is revised to read as follows:

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a and 2a to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE, an existing 4SLB stationary RICE, or an existing CI stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

■ 11. Section 63.6601 is added to read as follows:

§ 63.6601 What emission limitations must I meet if I own or operate a 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

■ 12. Section 63.6610 is amended by:

■ a. Revising the section heading;

■ b. Adding introductory text; and

■ c. Revising paragraphs (a) through (c).

The revisions and additions read as follows:

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

* * * * *

■ 13. Section 63.6611 is added to read as follows:

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an

initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

■ 14. Section 63.6625 is amended by adding paragraph (d) to read as follows:

§ 63.6625 What are my monitoring, installation, operation, and maintenance requirements?

* * * * *

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

■ 15. Section 63.6640 is amended by revising paragraph (e) to read as follows:

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

* * * * *

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate any stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing CI stationary RICE, an existing emergency stationary RICE, an existing limited use emergency stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

■ 16. Section 63.6645 is revised to read as follows:

§ 63.6645 What notifications must I submit and when?

(a) If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions or a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions, you must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2).

■ 17. Section 63.6665 is revised to read as follows:

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate any stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions: An existing 2SLB RICE, an existing 4SLB stationary RICE, an existing CI stationary RICE, an existing stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10

percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

■ 18. Section 63.6675 is amended by:
■ a. Adding definitions of "Compression Ignition," "Gasoline," and "Spark ignition" in alphabetical order;
■ b. Removing the definitions for "Compression ignition engine" and "Spark ignition engine;" and
■ c. Revising the definitions of "Emergency stationary RICE" and "Natural gas;" to read as follows:

§ 63.6675 What definitions apply to this subpart?

* * * * *

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

* * * * *

Emergency stationary RICE means any stationary RICE whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc. Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines. Emergency stationary RICE with a site-rating of more than 500 brake HP located at a major source of HAP emissions that were installed prior to June 12, 2006, may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE with a site-rating of more than 500 brake HP located at a major source of HAP emissions that were installed prior to June 12, 2006, may also operate an additional 50 hours per year in non-emergency situations. Emergency stationary RICE with a site-rating of more than 500 brake HP located at a major source of HAP emissions that were installed on or after June 12, 2006, must comply with requirements specified in 40 CFR 60.4243(d).

* * * * *

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

* * * * *

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

* * * * *

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

* * * * *

■ 19. Table 1a to Subpart ZZZZ of part 63 is revised to read as follows:

TABLE 1A TO SUBPART ZZZZ OF PART 63.—EMISSION LIMITATIONS FOR EXISTING, NEW, AND RECONSTRUCTED SPARK IGNITION, 4SRB STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

[As stated in § 63.6600, you must comply with the following emission limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions at 100 percent load plus or minus 10 percent]

For each...	You must meet the following emission limitations...
1. 4SRB stationary RICE	a. reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007; or b. limit the concentration of formaldehyde in the stationary RICE exhaust 350 ppbvd or less at 15 percent O_2.

■ 20. Table 1b to Subpart ZZZZ of Part 63 is revised to read as follows:

TABLE 1B TO SUBPART ZZZZ OF PART 63.—OPERATING LIMITATIONS FOR EXISTING, NEW, AND RECONSTRUCTED SPARK IGNITION, 4SRB STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

[As stated in §§ 63.6600, 63.6630 and 63.6640, you must comply with the following operating emission limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions]

For each...	You must meet the following operating limitation...
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR;. or	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and

TABLE 1B TO SUBPART ZZZZ OF PART 63.—OPERATING LIMITATIONS FOR EXISTING, NEW, AND RECONSTRUCTED SPARK IGNITION, 4SRB STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS—Continued

[As stated in §§ 63.6600, 63.6630 and 63.6640, you must comply with the following operating emission limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions]

For each...	You must meet the following operating limitation...
4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR..	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750°F and less than or equal to 1250°F.
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR;.	Comply with any operating limitations approved by the Administrator.
or	
4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR..	

■ 21. Table 2a to Subpart ZZZZ of Part 63 is revised to read as follows:

TABLE 2A TO SUBPART ZZZZ OF PART 63.—EMISSION LIMITATIONS FOR NEW AND RECONSTRUCTED 2SLB AND COMPRESSION IGNITION STATIONARY RICE >500 HP AND 4SLB STATIONARY RICE ≥250 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

[As stated in §§ 63.6600 and 63.6601, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent]

For each...	You must meet the following emission limitation...
1. 2SLB stationary RICE	a. reduce CO emissions by 58 percent or more; or b. limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007.
2. 4SLB stationary RICE	a. reduce CO emissions by 93 percent or more; or b. limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2.
3. CI stationary RICE	a. reduce CO emissions by 70 percent or more; or b. limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2.

■ 22. Table 2b to Subpart ZZZZ of Part 63 is revised to read as follows:

TABLE 2B TO SUBPART ZZZZ OF PART 63.—OPERATING LIMITATIONS FOR NEW AND RECONSTRUCTED 2SLB AND COMPRESSION IGNITION STATIONARY RICE >500 HP AND 4SLB BURN STATIONARY RICE ≥250 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

[As stated in §§ 63.6600, 63.6601, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary]

For each...	You must meet the following operating limitation...
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst.	Comply with any operating limitations approved by the Administrator.

■ 23. Table 4 to subpart ZZZZ of part 63 is revised to read as follows:

TABLE 4 TO SUBPART ZZZZ OF PART 63.—REQUIREMENTS FOR PERFORMANCE TESTS

[As stated in §§ 63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE]

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE.	a. Reduce CO emissions ..	i. Measure the O_2 at the inlet and outlet of the control device; and.	(1) Portable CO and O_2 analyzer.	(a) Using ASTM D6522–00 (2005) [a] (incorporated by reference, see § 63.14). Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device.	(1) Portable CO and O_2 analyzer.	(a) Using ASTM D6522–00 (2005) [a] (incorporated by reference, see § 63.14) or Method 10 of 40 CFR, appendix A. The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE ..	a. Reduce formaldehyde emissions.	i. Select the sampling port location and the number of traverse points; and.	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device; and.	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005)..	(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and.	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device.	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03 [b], provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde in the stationary RICE exhaust.	i. Select the sampling port location and the number of traverse points; and.	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and.	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005).	(a) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and.	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.

TABLE 4 TO SUBPART ZZZZ OF PART 63.—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

[As stated in §§ 63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE]

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		iv. Measure formaldehyde at the exhaust of the stationary RICE.	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03 [b], provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a] You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b] You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

■ 24. Table 8 to subpart ZZZZ of part 63 is revised to read as follows:

TABLE 8 TO SUBPART ZZZZ OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART ZZZZ

[As stated in § 63.6665, you must comply with the following applicable general provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions.	Yes.	
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6675.
§ 63.3	Units and abbreviations	Yes.	
§ 63.4	Prohibited activities and circumvention.	Yes.	
§ 63.5	Construction and reconstruction	Yes.	
§ 63.6(a)	Applicability	Yes.	
§ 63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources.	Yes.	
§ 63.6(b)(5)	Notification	Yes.	
§ 63.6(b)(6)	[Reserved].		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources.	Yes.	
§ 63.6(c)(1)–(2)	Compliance dates for existing sources.	Yes.	
§ 63.6(c)(3)–(4)	[Reserved].		
§ 36.6(c)(5)	Compliance dates for existing area sources that become major sources.	Yes.	
§ 63.6(d)	[Reserved].		
§ 63.6(e)(1)	Operation and maintenance	Yes.	
§ 63.6(e)(2)	[Reserved].		
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan.	Yes.	
§ 63.6(f)(1)	Applicability of standards except during startup shutdown malfunction (SSM).	Yes.	
§ 63.6(f)(2)	Methods for determining compliance.	Yes.	
§ 63.6(f)(3)	Finding of compliance	Yes.	
§ 63.6(g)(1)–(3)	Use of alternate standard	Yes.	
§ 63.6(h)	Opacity and visible emission standards.	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria.	Yes.	
§ 63.6(j)	Presidential compliance exemption.	Yes.	

TABLE 8 TO SUBPART ZZZZ OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART ZZZZ—Continued

[As stated in § 63.6665, you must comply with the following applicable general provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.7(a)(1)–(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§ 63.6610 and 63.6611.
§ 63.7(a)(3)	CAA section 114 authority	Yes.	
§ 63.7(b)(1)	Notification of performance test	Yes.	
§ 63.7(b)(2)	Notification of rescheduling	Yes.	
§ 63.7(c)	Quality assurance/test plan	Yes.	
§ 63.7(d)	Testing facilities	Yes.	
§ 63.7(e)(1)	Conditions for conducting performance tests.	Yes.	
§ 63.7(e)(2)	Conduct of performance tests and reduction of data.	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes.	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA.	Yes.	
§ 63.7(f)	Alternative test method provisions	Yes.	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting.	Yes.	
§ 63.7(h)	Waiver of tests	Yes.	
§ 63.8(a)(1)	Applicability of monitoring requirements.	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes.	
§ 63.8(a)(3)	[Reserved].		
§ 63.8(a)(4)	Monitoring for control devices	No.	
§ 63.8(b)(1)	Monitoring	Yes.	
§ 63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems.	Yes.	
§ 63.8(c)(1)	Monitoring system operation and maintenance.	Yes.	
§ 63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan.	Yes.	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements.	Yes.	
§ 63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements.	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§ 63.8(d)	CMS quality control	Yes.	
§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS.
§ 63.8(f)(1)–(5)	Alternative monitoring method	Yes.	
§ 63.8(f)(6)	Alternative to relative accuracy test.	Yes.	
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements.	Yes.	
§ 63.9(b)(1)–(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved.
§ 63.9(c)	Request for compliance extension	Yes.	
§ 63.9(d)	Notification of special compliance requirements for new sources.	Yes.	
§ 63.9(e)	Notification of performance test	Yes.	
§ 63.9(f)	Notification of visible emission (VE)/opacity test.	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(1)	Notification of performance evaluation.	Yes.	
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded.	Yes	If alternative is in use.

TABLE 8 TO SUBPART ZZZZ OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART ZZZZ—Continued

[As stated in § 63.6665, you must comply with the following applicable general provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.9(h)(1)–(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
§ 63.9(i)	Adjustment of submittal deadlines	Yes.	
§ 63.9(j)	Change in previous information	Yes.	
§ 63.10(a)	Administrative provisions for record keeping/reporting.	Yes.	
§ 63.10(b)(1)	Record retention	Yes.	
§ 63.10(b)(2)(i)–(v)	Records related to SSM	Yes.	
§ 63.10(b)(2)(vi)–(xi)	Records	Yes.	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes.	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA.	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation.	Yes.	
§ 63.10(b)(3)	Records of applicability determination.	Yes.	
§ 63.10(c)	Additional records for sources using CEMS.	Yes	Except that § 63.10(c)(2)–(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes.	
§ 63.10(d)(2)	Report of performance test results	Yes.	
§ 63.10(d)(3)	Reporting opacity or VE observations.	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes.	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports.	Yes.	
§ 63.10(e)(1) and (2)(i)	Additional CMS reports	Yes.	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports.	Yes	Except that § 63.10(e)(3)(i)(C) is reserved.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting.	Yes.	
§ 63.11	Flares	No.	
§ 63.12	State authority and delegations	Yes.	
§ 63.13	Addresses	Yes.	
§ 63.14	Incorporation by reference	Yes.	
§ 63.15	Availability of information	Yes.	

PART 85—[AMENDED]

■ 25. The authority citation for part 85 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 26. Section 85.2401 is amended by revising paragraph (a)(13) to read as follows:

§ 85.2401 To whom do these requirements apply?

(a) * * *

(13) Stationary internal combustion engines (See 40 CFR part 60, subparts IIII and JJJJ).

* * * * *

■ 27. Section 85.2403 is amended by revising paragraph (b)(11) to read as follows:

§ 85.2403 What definitions apply to this subpart?

* * * * *

(b) * * *

(11) 40 CFR part 60, subparts IIII and JJJJ.

■ 28. Section 85.2405 is amended by adding paragraph (f) to read as follows:

§ 85.2405 How much are the fees?

* * * * *

(f) Fees for stationary SI internal combustion engine certificate requests shall be calculated in the same manner as for NR SI certificate. Fees for certificate requests where the certificate would apply to stationary and mobile engines shall be calculated in the same manner as fees for the certificate requests for the applicable mobile source engines.

PART 90—[AMENDED]

■ 29. The authority citation for part 90 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 30. Section 90.1 is amended by adding paragraph (h) to read as follows:

§ 90.1 Applicability.

* * * * *

(h) This part applies as specified in 40 CFR part 60 subpart JJJJ, to spark-ignition engines subject to the standards of 40 CFR part 60, subpart JJJJ.

■ 31. Section 90.107 is amended by adding paragraph (d)(12) to read as follows:

§ 90.107 Application for certificate.

* * * * *

(d) * * *

(12) A statement indicating whether the engine family contains only nonroad engines, only stationary engines, or both.

* * * * *

■ 32. Section 90.114 is amended by revising paragraph (c)(7) and adding paragraph (g) to read as follows:

§ 90.114 Requirement of certification-engine information label.

* * * * *

(c) * * *

(7) The statement "THIS ENGINE CONFORMS TO U.S. EPA REGS FOR [MODEL YEAR].";

* * * * *

(g) Stationary engines required by 40 CFR part 60, subpart JJJJ, to meet the requirements of this part 90 must meet the labeling requirements of 40 CFR 60.4242.

■ 33. Section 90.201 is revised to read as follows:

§ 90.201 Applicability.

The requirements of this subpart C are applicable to all Phase 2 spark-ignition engines subject to the provisions of subpart A of this part except as provided in § 90.103(a). These provisions are not applicable to any Phase 1 engines. Participation in the averaging, banking and trading program is voluntary, but if a manufacturer elects to participate, it must do so in compliance with the regulations set forth in this subpart. The provisions of this subpart are applicable for $HC+NO_x$ ($NMHC+NO_x$) emissions but not for CO emissions. To the extent specified in 40 CFR part 60, subpart JJJJ, stationary engines certified under this part and subject to the standards of 40 CFR part 60, subpart JJJJ, may participate in the averaging, banking, and trading program described in this subpart.

PART 1048—[AMENDED]

■ 34. The authority citation for part 1048 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 35. Section 1048.1 is amended by revising paragraph (c) to read as follows:

§ 1048.1 Does this part apply to me?

* * * * *

(c) The definition of nonroad engine in 40 CFR 1068.30 excludes certain engines used in stationary applications. These engines may be required by 40 CFR part 60, subpart JJJJ, to comply with some of the provisions of this part 1048; otherwise, these engines are only required to comply with the requirements in § 1048.20. In addition, the prohibitions in 40 CFR 1068.101 restrict the use of stationary engines for nonstationary purposes unless they are certified under this part 1048 to the same standards that would apply to nonroad engines for the same model year.

* * * * *

■ 36. Section 1048.20 is amended by revising paragraph (a) introductory text, revising paragraph (b)(4) and adding paragraph (c) to read as follows:

§ 1048.20 What requirements from this part apply to excluded stationary engines?

(a) You must add a permanent label or tag to each new engine you produce or import that is excluded under § 1048.1(c) as a stationary engine and is not required by 40 CFR part 60, subpart JJJJ, to meet the standards and other requirements of this part 1048 that are equivalent to the requirements applicable to nonroad SI engines for the same model year. To meet labeling requirements, you must do the following things:

* * * * *

(b) * * *

(4) State: "THIS ENGINE IS EXCLUDED FROM THE REQUIREMENTS OF 40 CFR PART 1048 AS A "STATIONARY ENGINE" AND THE OWNER/OPERATOR MUST COMPLY WITH THE REQUIREMENTS OF 40 CFR PART 60. INSTALLING OR USING THIS ENGINE IN ANY OTHER APPLICATION MAY BE A VIOLATION OF FEDERAL LAW SUBJECT TO CIVIL PENALTY.".

(c) Stationary engines required by 40 CFR part 60, subpart JJJJ, to meet the requirements of this part 1048 must meet the labeling requirements of 40 CFR 60.4242.

■ 37. Section 1048.101 is amended by adding paragraph (a)(4) to read as follows:

§ 1048.101 What exhaust emission standards must my engines meet?

* * * * *

(a) * * *

(4) For constant-speed engines, the emission standards do not apply for transient testing if you do both of the following things:

(i) Demonstrate that the specified transient duty-cycle is not representative of the way your engines will operate in use.

(ii) Demonstrate that the engine's emission controls will function properly to control emissions during transient operation in use. In most cases, you may do this by showing that you use the same controls as a similar variable-speed engine that is certified as complying with the emission standards during transient testing.

* * * * *

■ 38. Section 1048.205 is amended by revising paragraphs (b) and (w) to read as follows:

§ 1048.205 What must I include in my application?

* * * * *

(b) Explain how the emission control systems operate. Describe the evaporative emission controls, if applicable. Also describe in detail all system components for controlling exhaust emissions, including all auxiliary emission control devices (AECDs) and all fuel-system components you will install on any production or test engine. Identify the part number of each component you describe. For this paragraph (b), treat as separate AECDs any devices that modulate or activate differently from each other. Include sufficient detail to allow us to evaluate whether the AECDs are consistent with the defeat device prohibition of § 1048.115.

* * * * *

(w) State whether your certification is intended to include engines used in stationary applications. Also state whether your certification is limited for certain engines. If this is the case, describe how you will prevent use of these engines in applications for which they are not certified. This applies for engines such as the following:

(1) Constant-speed engines.

(2) Variable-speed engines.

* * * * *

PART 1065—[AMENDED]

■ 39. The authority citation for part 1065 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 40. Section 1065.1 is amended by adding paragraph (a)(6) to read as follows:

§ 1065.1 Applicability.

(a) * * *

(6) Stationary spark-ignition engines certified using provisions in 40 CFR part 1048, as indicated under 40 CFR part 60, subpart JJJJ, the standard-setting part for these engines.

* * * * *

PART 1068—[AMENDED]

■ 41. The authority citation for part 1068 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 42. Section 1068.1 is amended by adding paragraph (a)(5) to read as follows:

§ 1068.1 Does this part apply to me?

(a) * * *

(5) Stationary spark-ignition engines certified using provisions in 40 CFR part

1048, as indicated under 40 CFR part 60, subpart JJJJ.

* * * * *

[FR Doc. E7–25394 Filed 1–17–08; 8:45 am]

BILLING CODE 6560–50–P

TABLE 3.—EPA APPROVED KNOX COUNTY, REGULATIONS

State citation	Title/subject	State effective date	EPA approval date	Explanation
* *	*	*	* *	*
13.0	Definitions	03/08/00	01/03/07 [Insert citation of publication].	
* *	*	*	* *	*
22.0	Regulation of Fugitive Dust and Materials.	1/10/01	01/03/07 [Insert citation of publication].	
* *	*	*	* *	*

* * * * *

[FR Doc. E6–22482 Filed 12–29–06; 8:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2004–0238; FRL–8264–1]

RIN 2060-AM16

National Emission Standards for Hazardous Air Pollutants for Source Categories From Oil and Natural Gas Production Facilities

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action promulgates national emission standards for hazardous air pollutants to regulate hazardous air pollutant emissions from oil and natural gas production facilities that are area sources. The final national emission standards for hazardous air pollutants for major sources was promulgated on June 17, 1999, but final action with respect to area sources was deferred. Oil and natural gas production is identified in the Urban Air Toxics Strategy as an area source category for regulation under section 112(c)(3) of the Clean Air Act because of benzene emissions from triethylene glycol dehydration units located at such facilities. This final rule also amends a general provision in the regulation to allow the use of an ASTM standard as an alternative test method to EPA Method 18 in the National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities.

DATES: This final rule is effective on January 3, 2007. The incorporation by reference of certain publications listed in these rules is approved by the Director of the Federal Register as of January 3, 2007.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2004–0238. All documents in the docket are listed either on the www.regulations.gov Web site or in the legacy docket, A–94–04. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through www.regulations.gov or in hard copy at the Air and Radiation Docket, EPA West, Room B–102, 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. **Note:** The EPA Docket Center suffered damage due to flooding during the last week of June 2006. The Docket Center is continuing to operate. However, during the cleanup, there will be temporary changes to Docket Center telephone numbers, addresses, and hours of operation for people who wish to make hand deliveries or visit the Public Reading Room to view documents. Consult EPA's **Federal Register** notice at 71 FR 38147 (July 5, 2006) or the EPA Web site at *http://www.epa.gov/epahome/dockets.htm* for current information on docket operations, locations, and telephone numbers. The Docket Center's mailing address for U.S. mail and the procedure for submitting comments to www.regulations.gov are not affected by the flooding and will remain the same.

FOR FURTHER INFORMATION CONTACT: Greg Nizich, 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) 541–3078; fax number: (919) 541–0246; e-mail address: *nizich.greg@epa.gov*.

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Entities potentially affected by this final rule include, but are not limited to, the following:

Category	NAICS Code*	Examples of regulated entities
Industry	211111, 211112	Condensate tank batteries, glycol dehydration units, and natural gas processing plants.

* 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 part 63, subpart HH, National Emissions Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities. 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.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of this final rule is also

available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following the Administrator's signature, a copy of this final rule 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.

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 United States Court of Appeals for the District of Columbia Circuit by March 5, 2007. Only those objections to this final rule that were raised with reasonable specificity during the period for public comment may be raised during judicial review. Under section 307(b)(2) of the CAA, the requirements that are the subject of this final rule may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA further 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.

Organization of this Document. The information presented in this preamble is organized as follows:

I. Background Information
A. What is the statutory authority for this final rule?
B. What criteria are used in the development of area source standards?
C. How was this final rule developed?
II. Summary of This Final Rule
A. What source categories are affected by this final rule?
B. What is the affected source?
C. What pollutants are emitted and controlled?
D. Does this final rule apply to me?
E. What are the emission limitations and work practice standards?
F. What are the testing and initial compliance requirements?
G. What are the continuous compliance requirements?
III. Significant Changes Since Proposal
A. Compliance Dates
B. Applicability Requirements
C. Startup, Shutdown, and Malfunction Requirements
IV. Responses To Significant Comments
A. What geographic applicability criteria is being used in this final rule?
B. What urban definition is being used in this final rule?
C. What are the requirements for remote/unmanned sources?
V. Impacts of This Final Rule
A. What Are The Air Impacts?
B. What Are The Cost Impacts?
C. What Are The Economic Impacts?
D. What Are The Non-Air Environmental and Energy Impacts?
VI. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act of 1995
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Congressional Review Act

I. Background Information

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

Sections 112(c)(3) and 112(k)(3)(B) of the CAA instruct us to identify not less than 30 hazardous air pollutants (HAP) which, as a result of emissions from area sources,[1] present the greatest threat to public health in the largest number of urban areas, and to list sufficient source categories or subcategories to ensure that 90 percent of the emissions of the listed HAP (area source HAP) are subject to regulation. CAA Section 112(c)(3) requires us to regulate these listed area source categories under CAA section 112(d). Section 112(d)(5) of the CAA provides us with the discretion to set standards for area sources according to generally available control technologies (GACT) or management practices in lieu of maximum achievable control technologies (MACT). Unlike MACT, there is no prescription in CAA section 112(d)(5) that standards for existing sources must, at a minimum, be set at the level of emission reduction achieved by the best performing 12 percent of existing sources, or that standards for new sources be set at the level of emission reduction achieved in practice by the best controlled similar source. The legislative history suggests that standards under CAA section 112(d)(5) should "[reflect] application of generally available control technology—that is, methods, practices, and techniques which are commercially available and appropriate for application by the sources in the category considering economic impacts and the technical capabilities of the firms to operate and maintain the emissions control systems." SEN. REP. NO. 101–228, at 171 (1989). Thus, by contrast to MACT, CAA section 112(d)(5) allows us to consider various factors in determining the appropriate standard for a given area source category.

B. What criteria are used in the development of area source standards?

We are issuing standards for this area source category under CAA section 112(d)(5), in lieu of a MACT standard. There are factors relevant to this area source category that warrant our consideration, and we can properly assess those factors under section 112(d)(5) of the CAA. For example, the locations of oil and natural gas production sources are dictated by the locations of the relevant natural resources rather than a need to serve a particular population center. In addition, these sources do not typically require on-site operators and are usually not manned by large staff, if manned at all. Given the unique nature of these sources, many of these sources are located in remote areas. We believe that a CAA section 112(d)(5) standard is appropriate because it would allow us to adequately address these and other relevant factors, including costs, in promulgating these national emission standards for hazardous air pollutants (NESHAP).

C. How was this final rule developed?

We initially proposed NESHAP for the Oil and Natural Gas Production source category on February 6, 1998 (63 FR 6288) that addressed both major and area source oil and natural gas production facilities. CAA Section

[1] Under section 112(a) of the CAA, an area source is a stationary source that is not a major source. A major source, as defined under section 112(a) of the CAA, is a stationary source or a group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP.

112(c)(3) authorizes us to list for regulation an area source category "which the Administrator finds present a threat of adverse effects to human health or the environment * * * warranting regulation." In the 1998 proposed NESHAP, we proposed to regulate this area source category pursuant to CAA section 112(c)(3) due to the risks from exposure to benzene emissions from triethylene glycol (TEG) dehydration units at these area sources. Public comments were solicited at the time of the proposal. We received 29 comment letters on the proposed area source standards. On June 17, 1999, we promulgated the NESHAP for major sources of oil and natural gas production (64 FR 32610) but did not finalize either the 1998 proposed listing of this area source category for regulation or the proposed area source standards. Instead, on July 19, 1999, we published the Urban Air Toxics Strategy (Strategy) (64 FR 38706, July 19, 1999). The Strategy included benzene as one of the 30 listed area source HAP under CAA section 112(k)(3)(B)(i). The Strategy also listed oil and natural gas production for regulation under CAA section 112(k)(3)(B)(ii) because TEG dehydration units at oil and natural gas production facilities contributed approximately 47 percent of the national urban benzene emissions from area sources. On July 8, 2005 (70 FR 39443), we published a supplemental proposal to the 1998 proposed area source standards. The 60-day comment period ended on September 6, 2005, and we received 18 comment letters on the supplemental proposal. Today's final rule reflects our consideration of all of the comments received on both the 1998 and 2005 proposed standards for area sources of oil and natural gas production.

II. Summary of This Final Rule

A. What source categories are affected by this final rule?

This final rule affects area source oil and natural gas production facilities. An oil and natural gas production facility processes, upgrades, or stores (1) hydrocarbon liquids (with the exception of those facilities that exclusively handle black oil) to the point of custody transfer and (2) natural gas from the well up to and including the natural gas processing plant.

B. What is the affected source?

In this final rule, the affected source is defined as each TEG dehydration unit located at an area source oil and natural gas production facility. Other types of dehydration units or other emission points (*e.g.*, equipment leaks) at area source oil and natural gas production facilities are not a part of the affected source.

C. What pollutants are emitted and controlled?

The primary HAP associated with oil and natural gas production facilities include benzene, toluene, ethylbenzene, and mixed xylenes and n-hexane. Only benzene is listed under CAA section 112(k)(3)(B)(i) as one of the 30 area source HAP. Benzene is classified as a known human carcinogen based on convincing human evidence (such as observed increases in the incidence of leukemia in exposed workers), as well as supporting evidence from animal studies. In addition, short-term inhalation of high benzene levels may cause nervous system effects such as drowsiness, dizziness, headaches, and unconsciousness in humans. At even higher concentrations of benzene, exposure may cause death, while lower concentrations may irritate the skin, eyes, and upper respiratory tract. Long-term inhalation exposure to benzene may cause various disorders of the blood and toxicity to the immune system. Reproductive disorders in women, as well as developmental effects in animals, have also been reported for benzene exposure.

Benzene emissions from TEG dehydration units at oil and natural gas production facilities contributed approximately 47 percent of the nationwide urban area source benzene emissions. Accordingly, this final rule regulates benzene emissions from TEG dehydration units at area source oil and natural gas production facilities.

D. Does this final rule apply to me?

You are subject to emissions reduction requirements in this final rule if you own or operate a TEG dehydration unit with an actual annual average natural gas flow rate equal to or greater than 85 thousand standard cubic meters per day (thousand m^3/day) (3 million standard cubic feet per day (MMSCF/D)), and with benzene emissions equal to or greater than 0.90 Megagrams per year (Mg/yr) (1.0 ton per year (tpy)).

E. What are the emission limitations and work practice standards?

We created three subcategories of sources in this final rule. We created a subcategory of TEG dehydration units with either an annual average natural gas flowrate less than 85 thousand m^3/day (3 MMSCF/D) or benzene emissions less than 0.90 Mg/yr (1.0 tpy). As explained in the supplemental proposed rule, we determined that GACT is no control for these sources. We did not receive any comments on this determination.

As for those TEG dehydration units with an annual average natural gas flow rate equal to or greater than 85 thousand m^3/day (3 MMSCF/D) and benzene emissions equal to or greater than 0.90 Mg/yr (1.0 tpy), we subcategorized these units based on their locations with regard to areas of higher population densities. In evaluating population density, we started with the U.S. Census Bureau terms of "urbanized area" and "urban cluster." Upon evaluating the characteristics of this area source category, we define areas of higher population densities to be urbanized areas (UA),[2] urban clusters (UC)[3] that contain 10,000 people or more,[4] and the area located two miles[5] or less from each UA boundary. For ease of reference, this final rule refers to these areas as "UA plus offset and UC." As mentioned above, UA and UC are terms used by the United States Census Bureau to identify densely settled areas. Among other Census Bureau criteria, an UA has a population of at least 50,000 people, and an UC has a population of at least 2,500, but less than 50,000 people.

For those area source TEG dehydration units with natural gas throughput and benzene emission rates above the cutoff levels described above that are located within the UA plus offset and UC boundary, we are requiring, pursuant to CAA section 112(d)(5), that each such unit be connected, through a closed vent system, to one or more emission control devices. The control devices must: (1) Reduce HAP emissions by 95 percent or more (generally by a condenser with a

[2] *Urbanized area (UA)* refers to Census 2000 Urbanized Area, which is defined in the *Urban Area Criteria for Census* 2000, 67 FR 11663, 11667 (March 15, 2002). Essentially, an UA consists of densely settled territory with a population of at least 50,000 people.

[3] *Urban cluster (UC)* refers to Census 2000 Urban Cluster, which is defined in the *Urban Area Criteria for Census* 2000, 67 FR 11667. Essentially, an UC consists of densely settled territory with at least 2,500 people, but fewer than 50,000 people.

[4] This final rule does not cover all UC areas, but only those UC areas that contain 10,000 people or more, which are used to construct Census 2000 core-based statistical areas (65 FR 82233).

[5] We determined the 2-mile offset distance by reviewing maps of different UA areas and measuring the distance across the largest pockets or holes within the UA footprint. Since our evaluations showed that the largest distance was just under 4 miles across, we decided to use one half of that distance, i.e., 2 miles, as the offset distance. This would ensure that any sources located within a pocket or hole would be controlled as part of the UA source-group. Since we did not find the presence of holes in UC's, no offset is provided.

flash tank); or (2) reduce HAP emissions to an outlet concentration of 20 parts per million by volume (ppmv) or less (for combustion devices); or (3) reduce benzene emissions to a level less than 0.90 Mg/yr (1.0 tpy). As an alternative to complying with these control requirements, pollution prevention measures such as process modifications or combinations of process modifications and one or more control devices that reduce the amount of HAP generated, are allowed provided that they achieve the same required emission reductions.

For those area source TEG dehydration units with natural gas throughput and benzene emission rates above the cutoff levels described above that are located outside of UA plus offset and UC boundaries, we are requiring, pursuant to CAA section 112(d)(5), that each unit reduce emissions by lowering the glycol circulation rate to be less than or equal to an optimum rate. The optimum rate is determined by the following equation:

$$L_{OPT} = 1.15 * 3.0 \frac{\text{gal TEG}}{\text{lb } H_2O} * \left(\frac{F * (I - O)}{24 \text{ hr/day}} \right)$$

Where:

L_{OPT} = Optimal circulation rate, gal/hr.
F = Gas flowrate (MMSCF/D).
I = Inlet water content (lb/MMSCF), and
O = Outlet water content (lb/MMSCF).

The constant 3.0 gal TEG/lb H_2O is the industry accepted rule of thumb for a TEG-to-water ratio. The constant 1.15 is an adjustment factor included for a margin of safety.

We decided to subcategorize in the manner described above for several reasons. We received a number of comments on both the 1998 and 2005 proposals that this source category contains many sources that are located in remote areas. Our understanding of this area source category is consistent with the comment on the remoteness of the locations of many of these sources. We recognize that the oil and natural gas production source category is unique compared to many other area source categories in that the location of these sources is dictated by the location of the relevant natural resources rather than a need to serve a particular population center. In addition, sources in this category do not typically require on-site operators and are usually not manned by large staff, if manned at all. As previously mentioned, we believe that the standards need to be tailored to appropriately address these unique circumstances.

In conducting our analysis, we compared the impacts of applying the add-on control requirement described above to TEG dehydration units nationwide to the impacts of only applying the requirement to units located in areas of high population densities (i.e., within the UA plus offset and UC boundary).[6] Applying the add-on control to the estimated 2,222 TEG dehydration units nationwide would result in approximately 13,400 tpy of HAP (4,020 tpy of benzene) emission reduction. We estimate that these 2,222 TEG dehydration units are located in States with a combined population of 92 million people.[7] The annual cost for this option was estimated to be $39 million. We then evaluated the impacts of applying the add-on control requirement to only those TEG dehydration units located within UA plus offset and UC boundaries. We estimated 50 TEG dehydration units in this area with a combined population of 80 million people. This scenario would result in a 300 tpy HAP (90 tpy of benzene) emission reduction and an annual cost of compliance of $883 thousand. Thus, extending the add-on control requirement to sources outside the UA plus offset and UC boundaries would result in an additional annual cost exceeding $38 million in an area with a combined population of 12 million people. This analysis showed that the overall cost of controlling units outside UA plus offset and UC boundaries was much higher for a lower population.

Since the areas located outside UA plus offset and UC boundaries are sparsely populated compared to those inside UA plus offset and UC boundaries, we do not believe the additional cost associated with extending the add-on control requirement to sources in this area is justified. Under this final rule, the add-on control requirement applies only to sources located within the UA plus offset and UC boundaries. Section 112(d)(5) of the CAA authorizes us to set standards for area sources that provide for the use of generally available management practices by sources to reduce HAP emissions. Pursuant to CAA section 112(d)(5), we have prescribed a management practice for sources located outside the UA plus offset and UC boundaries. We have determined that adjusting the TEG circulation rate is an appropriate management practice for several reasons. First, by lowering the TEG circulation rate, the amount of glycol that comes in contact with the natural gas is reduced, thereby lowering the amount of HAP (e.g., benzene) that is absorbed by the glycol and subsequently emitted through the reboiler vent when the glycol is regenerated. We estimate that the HAP emissions reduction is approximately 7,600 tpy (2,400 tpy of benzene) for the approximately 2,172 sources located outside UA plus offset and UC boundaries. Second, reducing the TEG circulation rate has the added benefit of reducing natural gas losses. Natural gas is also absorbed by the TEG, and subsequently emitted through the reboiler vent. The amount of natural gas vented is directly proportional to the TEG circulation rate. Lowering the TEG circulation rate has a direct impact on the amount of natural gas lost. Third, optimizing the TEG circulation rate can be achieved without sacrificing the performance of the TEG dehydration unit. Fourth, this process variable does not require the presence of an on-site operator to maintain and, thus, would be an achievable option for unmanned sources. Finally, the TEG circulation rate can be optimized for minimal capital cost (e.g., a new pump may be required) and could result in an annual cost savings due to the reduction of the natural gas losses. Therefore, this final rule requires each TEG dehydration unit at area source oil and natural gas production facilities located outside of UA plus offset and UC boundaries to reduce emissions by optimizing the TEG circulation rate.

F. What are the testing and initial compliance requirements?

To demonstrate that the actual annual average natural gas flowrate of your TEG dehydration unit is less than 85 thousand m^3/day (3 MMSCF/D), this final rule specifies that you must determine the natural gas flow rate using either a flow measurement device or another method approved by the Administrator. To demonstrate that your TEG dehydration unit emits less than 0.90 Mg/yr (1.0 tpy) of benzene, this final rule specifies that you must determine its emissions using either GRI–GLYCalc™, Version 3.0 or higher, or direct measurement.

For TEG dehydration units that have an actual annual average natural gas flowrate and benzene emission rate at or above the cut-off levels mentioned above and are located within the UA

[6] Because we have determined that GACT is no control for units below the natural gas throughput and benzene emission threshold, we only considered the impacts of sources above the thresholds.

[7] We are using an approach by which we are evaluating the affected TEG dehydration units relative to the populations contained in the top 13 natural gas producing States (Texas, New Mexico, Oklahoma, Wyoming, Louisiana, Colorado, Alaska, Kansas, California, Utah, Michigan, Alabama, and Mississippi). This approach is consistent with that used in the July 2005 proposal (70 FR 39446).

plus offset and UC boundaries, the source must submit Notification of Compliance Status Reports, inspect/test the closed-vent system and control device(s), and establish monitoring parameter values. If the unit is above the cut-offs and located outside the UA plus offset and UC boundaries, the source only has to submit an Initial Notification which must include a certified statement of future compliance.

We are finalizing the change proposed in the July 8, 2005 notice to allow ASTM D6420–99 (2004) as an alternative where EPA Method 18 is specified. The General Provisions of 40 CFR part 63 will be amended to incorporate the approved method by reference for 40 CFR part 63, subpart HH. See section VI.J. for further discussion.

G. What are the continuous compliance requirements?

Area sources within UA plus offset and UC boundaries are required to submit periodic reports on an annual basis, instead of semiannually, as is required for major sources. Continuous compliance requirements include submitting periodic reports, conducting annual inspections of closed-vent systems, repairing leaks and defects, conducting the required monitoring, and maintaining the required records. As described in the 1998 proposal and the 2005 proposal, these monitoring, recordkeeping, and reporting requirements are the same as those required for major sources except for the frequency of submittal for periodic reports. Sources outside the UA plus offset and UC boundaries must maintain a record of the circulation rate determination.

III. Significant Changes Since Proposal

A. Compliance Dates

The compliance date provisions for existing sources in this final rule differ from the two proposed rules in two respects. First, because we have added a management practice requirement to this final rule, we included a 2-year compliance deadline for existing sources subject to this requirement. The management practice requirement would require, at most, that a source install a new glycol pump to optimize the TEG circulation rate. We believe that 2 years is a sufficient length of time in which to install and operate the glycol pump at the optimum circulation rate. We considered making the compliance deadline 1 year, however we decided that given the estimated 2,172 sources required to implement this management practice, a 2-year compliance period was more appropriate.

Second, we use the date of the 1998 proposed rule for defining existing and new sources in "Urban-1" counties only. In the 2005 supplemental proposal, we used the date of the 1998 proposed rule to define new and existing sources in both Urban-1 and "Urban-2" counties, because we had proposed to regulate sources in these counties in the 1998 proposed rule.[8] Since then, we concluded that defining existing and new sources in Urban-2 counties based on the date of the 1998 proposed rule would be inappropriate because the 1998 proposed rule contained an inaccurate definition for Urban-2 and, therefore, did not provide adequate notice to sources in Urban-2 counties. Accordingly, this final rule uses the date of the 1998 proposal for defining existing and new sources in Urban-1 counties only. For sources in areas other than Urban-1 counties, this final rule determines existing and new sources based on the date of the 2005 supplemental proposal.

Table 1 of this preamble presents compliance dates for existing and new sources for this final rule.

For an affected source located in a county we classified as * * *	and is located * * *	where the source was constructed/re-construct-ed * * *	then the source is * * *	and the compliance date for that source would be * * *
(a) Urban-1 based on 2000 census data,	within any UA plus offset and UC boundary,	before February 6, 1998,	Existing	January 4, 2010.
(b) Urban-1 based on 2000 census data,	Not within any UA plus offset and UC boundary,	before February 6, 1998,	Existing	January 5, 2009.
(c) Urban-1 based on 2000 census data,	either within or outside any UA plus offset and UC boundary,	on or after February 6, 1998,	New	January 3, 2007 or startup, whichever is later.
(d) Not Urban-1 based on 2000 census data,	within any UA plus offset and UC boundary,	before July 8, 2005,	Existing	January 4, 2010.
(e) Not Urban-1 based on 2000 census data,	Not within any UA plus offset and UC boundary,	before July 8, 2005,	Existing	January 5, 2009.
(f) Not Urban-1 based on 2000 census data,	Either within or outside any UA plus offset and UC boundary,	on or after July 8, 2005,	New	January 3, 2007 or startup, whichever is later.

B. Applicability Requirements

Whereas the proposed rules proposed applying the add-on control requirement either nationally or only to TEG dehydration units at sources located in "urban" counties, this final rule applies this requirement to: Units at area sources located within a UA plus offset and UC boundary, which is described in section II.E above. Units at area sources not located within the UA plus offset and UC boundaries must implement the prescribed management practices (i.e., adjust TEG circulation rate) for operation of the TEG dehydration unit. Guidance is available on the Internet at *http://www.epa.gov/ttn/atw/oilgas/oilgaspg.html* to assist in determining your location relative to a UA plus offset and UC boundary, or you can access the Bureau of Census Web site at *http://factfinder.census.gov* to generate a map based on the location of your TEG dehydration unit and calculate the location relative to the nearest UA plus offset and UC boundaries.

[8] Both the 1998 and 2005 proposed rules provided definitions for "Urban-1" and "Urban-2." However, we did not accurately define "Urban-2" in the 1998 proposed rule. The definition for "Urban-2" was corrected in the 2005 supplemental proposed rule.

C. Startup, Shutdown, and Malfunction Requirements

This final rule follows the requirements of the General Provisions (40 CFR part 63, subpart A) regarding startup, shutdown, and malfunction (SSM) events. Because this final rule only requires area sources within UA plus offset and UC boundaries to have add-on control, only sources within the UA plus offset and UC boundaries are subject to the General Provisions regarding SSM.

IV. Responses to Significant Comments

Our responses to all of the significant public comments on both proposals are presented in the Response to Comments Document which is available in Docket No. EPA–HQ–OAR–2004–0238.

A. What Geographic Applicability Criteria is Being Used in this final rule?

Comment: We proposed two options for the geographic applicability criteria: (1) all TEG dehydration units would be subject to area source standards (hereinafter referred to as "Option 1"); and (2) area source standards would apply to TEG dehydration units located in Urban-1 and Urban-2 counties (hereinafter referred to as "Option 2"). We received comments objecting to Option 1 for primarily two reasons: (1) EPA does not have the authority to regulate rural sources under the CAA; and (2) regulation of rural or remote sources is not warranted due to low exposure risks.

The commenters stated that nationwide applicability is contrary to the plain language of the CAA, specifically section 112(k). According to the commenters, CAA section 112(k) is designed to address those smaller sources of HAP that create unacceptable exposures in concentrated urban areas; remote, small, or sparsely populated rural areas, where many dehydrators are located, are therefore not within the scope of CAA section 112(k)(1). Several commenters stated that there is no clear indication that emissions from remote sources provide a meaningful contribution to ambient air toxic levels in urban areas; therefore, regulating rural sources would not have the effect intended by the CAA.

We also received comments objecting to Option 1 asserting that exposure risks from facilities located in rural or remote areas are low or nonexistent. One commenter stressed that the foundation for the area source program was based on regulating area sources in a manner that would result in a public health benefit. The commenter stated that regulating dehydration units in rural areas, which are sparsely populated, would not yield the same public health benefits that were "contemplated" by the statute.

Response: We believe that the CAA provides the Agency with the authority to regulate area sources nationwide. CAA section 112(k)(1) states that "It is the purpose of this subsection to achieve a substantial reduction in emissions of hazardous air pollutants from area sources and an equivalent reduction in the public health risks associated with such sources including a reduction of not less than 75 per centum in the incidence of cancer attributable to emissions from such sources." Consistent with this expressed purpose of CAA section 112(k) to reduce both emissions and risks, CAA section 112(k)(3)(i) requires that we list not less than 30 HAP that, as a result of emissions from area sources, present the greatest threat to public health in the largest number of urban areas. CAA sections 112(c)(3) and (k)(3)(ii) require that we list area source categories that represent not less than 90 percent of the area source emissions of each of the listed HAP. CAA section 112(c) requires that we issue standards for listed categories under CAA section 112(d). These relevant statutory provisions authorize us to regulate listed area source categories and not just sources located in urban areas.

In both the UATS and our July 8, 2005 supplemental proposal, we identified the reasons supporting a national rule (e.g., benzene's toxicity and carcinogenicity, a level playing field, the 75 percent cancer incidence reduction goal) (64 FR 38724 and 70 FR 39446). Furthermore, by requiring management practices rather than control requirements on sources outside the UA plus offset and UC boundaries, we believe that we have appropriately addressed commenters' concern with respect to remote sources being subject to unnecessary or costly requirements.

B. What urban definition is being used in this final rule?

Comment: Several commenters opposed EPA's definition of "urban areas." According to the commenters, by defining urban areas as county-wide areas, EPA has expanded urban areas to include large expanses of rural territories. One commenter stated that a comparison of land area to population on a county basis shows that the target population for protection is very thinly distributed. Four commenters referred to maps noting that the maps show vast areas of the United States that would be classified as urban areas based on the proposed definition, but have very low population. The commenters specifically referred to the State of Wyoming, in which half of the State is classified as "urban" using EPA's proposed definition. One commenter also pointed out that in Utah, six of the 12 counties designated as urban using EPA's definition have a population density of less than ten persons per square mile.

Other commenters stated that some counties with a total population of less than 5,000, and an average population density of less than two people per square mile, would be classified as urban under the Urban-2 designation. In order to illustrate the broad geographical applicability that includes remote locations, the commenters stated that, based on the Urban-2 definition, urban designations would be applied to:

- 14 of 23 counties in Wyoming;
- 20 of 33 counties in New Mexico;
- 10 or 17 counties in Nevada; and
- 17 of 56 counties in Montana.

One commenter stated that EPA's proposed definition of urban areas would be unnecessarily costly and burdensome on sites located in rural or remote areas, but classified as urban. One commenter acknowledged that there has been, and will continue to be, instances of energy production and population encroachment. However, according to the commenter, most of the known conventional or unconventional gas supply basins are likely to remain rural for the foreseeable future.

Response: The statute does not define urban, thus, leaving us the discretion to define the term. We proposed and took comments on our definition of the term urban as part of our 1999 UATS. The definition was the basis for the listing of area source categories pursuant to section 112(c)(3) and (k)(3)(B)(ii) of the CAA. We are currently under court-ordered deadlines to complete issuing standards for all listed area source categories. Changing the definition of urban would mean recreating an area source category list, which may differ significantly from the current list and, thus, greatly hinders our effort to complete our obligation by the court-ordered deadlines. Therefore, we believe that revisiting the definition of urban is inappropriate at this time. However, we have tailored this rule to address the unique circumstances associated with this source category, as described above. Moreover, in response to comments regarding the nature of remote sources, we modified this final rule and are only requiring the add-on control requirement for sources in areas of higher population densities, which we have identified as areas within the UA plus offset and UC boundaries. This

rule imposes the less costly management practice requirements on sources outside the UA plus offset and UC boundaries.

C. What are the requirements for remote/unmanned sources?

Comment: Commenters said if EPA imposes controls on TEG dehydrators outside of Urban-1 areas, it should adopt a separate (lesser) control standard for those remote area sources for the following reasons:

- It is not justified based on health effects.
- Practical considerations prevent operators from achieving the 95-percent control efficiency on remote, unmanned TEG dehydrators.

Commenters said that in order to meet the 95-percent control efficiency or the outlet concentration, an operator generally has to install a system with a forced draft fan for the condenser and a flare or vapor recovery system. Many remote sources do not have an electric power supply, which precludes using a forced draft fan. Routing the vapors to the firebox or fire-tube is not practical in all situations because the high water vapor content can extinguish the fire. While flares and vapor recovery systems address this problem, they require frequent monitoring, which is a problem at unmanned sites that are only visited infrequently. The lack of electric power supply would make certain automated monitoring systems impossible.

Commenters said EPA should adopt a separate GACT standard for facilities outside of "Urban-1" areas and "urbanized areas." The 95-percent control efficiency standard could still apply in Urban-1 areas and urbanized areas, but it would not otherwise apply to area source TEG dehydrators. The commenters recommended that EPA set GACT for facilities that are not located in Urban-1 or urbanized areas as a reduction of benzene to a level of less than 1 tpy, and remove the 95-percent control efficiency requirement. One commenter added that GACT could also be considered as the installation of a flash tank/condenser or incinerator process.

Response: We agree with the commenters that it is reasonable to require a higher level of emission reductions for TEG dehydration units located in more densely populated areas. We also recognize that the oil and natural gas source category is unique because there are many area sources that are located in remote or rural areas. For these reasons and the reasons discussed above, we have subcategorized to differentiate between those sources above the cutoff levels identified above that are located inside UA plus offset and UC boundaries and those located outside such boundaries. We require installation of control equipment for TEG dehydration units located inside UA plus offset and UC boundaries and management practices (i.e., optimized glycol circulation rate) for units located outside UA plus offset and UC boundaries. We believe that this approach addresses the commenters' concerns regarding the control of remote or rural facilities.

V. Impacts of This Final Rule

The environmental and cost impacts for this final rule are presented in Table 2 of this preamble:

	Existing	New
Total Number of Impacted Facilities	2,222	*141
Facilities Required to Install Add-On Controls		
Number of Facilities	50	3
Emission Reductions (Mg/yr):		
HAP	300	17
VOC	530	30
Benzene	90	5
Secondary Emissions Increases (Mg/yr):		
SO_2	<1	<1
NO_X	<1	<1
CO	<1	<1
Cost Impacts:		
Total Capital Investment (1,000 $/yr)	850	35
Total Annual Cost (1,000 $/yr)	880	50
Facilities Required to Implement Management Practices		
Number of Facilities	2,172	138
Emission Reductions (Mg/yr):		
HAP	6,900	440
VOC	14,020	890
Benzene	2,200	140
Cost Impacts:		
Total Capital Investment (1,000 $/yr)	1,700	105
Total Annual Cost without considering gas savings (1,000 $/yr)	14,200	905
Total Annual gas savings (1,000 $/yr)	(12,600)	(800)
Total Annual Cost considering gas savings (1,000 $/yr)	1,600	105

*New source estimates are estimated by determining the average number of new sources per year.

A. What Are the Air Impacts?

For existing area source TEG dehydration units in the oil and natural gas production source category, we estimate that nationwide baseline area sources HAP emissions are 45,100 Mg/yr (49,600 tpy) and 13,500 Mg/yr of benzene (14,800 tpy). The final standards require that TEG dehydration units with a natural gas throughput greater than 85 thousand m^3/day (3 MMSCF/D) and benzene emissions greater than 0.90 Mg/yr (1.0 tpy), located within the UA plus offset and UC boundaries achieve a 95-percent emission reduction or reduce benzene emissions to less than 0.90 Mg/yr (1.0 tpy) either through pollution prevention process changes or by installing a control device (e.g., condenser), while sources located outside the UA plus

offset and UC boundaries optimize their glycol circulation rate. We estimate that this final rule will result in a HAP emission reduction of 7,200 Mg/yr (7,900 tpy) and 2,200 Mg/yr of benzene (2,400 tpy).

To estimate the impacts of this final rule on new sources, we assumed that new area source facilities would, in the absence of the standards, have baseline emissions equivalent to existing sources. We estimate that a total of 7,200 new area source TEG dehydration units will be constructed within the next 5 years, or 2,400 per year. Of these 7,200 new area source TEG dehydration units, we estimate that a total of 423 (141 per year) will have an actual annual average natural gas flowrate greater than or equal to 85 thousand m^3/day (3 MMSCF/D). Using these assumptions, we estimate the nationwide emission reduction resulting from new area source TEG dehydration units complying with this final rule would be approximately 450 Mg/yr (500 tpy) of HAP and 140 Mg/yr (150 tpy) of benzene from the 141 new area sources that would become subject each year. We assume that, of the 141 new area sources, 3 would be located within the UA plus offset and UC boundaries and 138 would be located outside the boundaries.

Secondary environmental impacts are considered to be any air, water, or solid waste impacts, positive or negative, associated with the implementation of the final standards. These impacts are exclusive of the direct organic HAP air emissions reductions discussed in the previous section.

The capture and control of benzene that is presently emitted from area source TEG dehydration units will result in a decrease in volatile organic compound (VOC) emissions as well. The estimated total VOC emissions reductions are 14,550 Mg/yr (16,000 tpy) from existing sources.

Other secondary environmental impacts are those associated with the operation of certain air emission control devices (i.e., flares). The adverse secondary air impacts would be minimal in comparison to the primary HAP reduction benefits from implementing the final control requirements for area sources. We estimate that the national annual increase of secondary air pollutant emissions resulting from the use of a flare to comply with the final standards is less than 1 Mg/yr for sulfur oxides, 1 Mg/yr for carbon monoxide, and 1 Mg/yr for nitrogen oxides.

B. What are the Cost Impacts?

Since several compliance options are available to owners/operators of affected sources subject to the add-on control requirement, we are not sure what control method will be employed. Sources can control emissions by routing emissions to a condenser, a flare, a process heater, or back to the process or by implementing pollution prevention process changes. For the cost estimates developed for condenser systems, we looked at systems with and without the use of a gas condensate glycol separator (GCG separator) or flash tank in TEG dehydration system design. We estimate that approximately 50 sources are located within the UA plus offset and UC boundaries. For the new source cost impacts, we assumed that new area source TEG dehydration units will be constructed with a flash tank.

Affected sources located outside of UA plus offset and UC boundaries are required to operate the TEG dehydration unit at the optimum glycol circulation rate. For estimating annual costs for these sources, it was assumed that in order to meet the optimum glycol circulation rate, owners or operators would be required to purchase and install a new pump. Because reducing the glycol circulation rate to an optimum level reduces gas losses, a recovery credit is also associated with this requirement. Although we believe a minority of sources will have to install a new pump to meet the management practice requirements, costs were estimated by assuming that 50 percent of the 2,172 sources would have to install a new pump while the other 50 percent could lower the circulation rate sufficiently by making adjustments on the existing pump.

The estimated annual costs shown in Table 2 of this preamble include the capital cost; operating and maintenance costs; the cost of monitoring, inspection, recordkeeping, and reporting; and any associated product recovery credits.

C. What are the Economic Impacts?

For the 1998 proposal, we prepared an economic impact analysis evaluating the impacts of the rule on affected producers, consumers, and society. The economic analysis focused on the regulatory effects on the United States natural gas market that is modeled as a national, perfectly competitive market for a homogenous commodity.

The results of the analysis showed that the imposition of regulatory costs on the natural gas market would result in negligible changes in natural gas prices, output, employment, foreign trade, and business closures. The price and output changes as a result of the 1998 proposed regulation were estimated to be less than 0.01 percent, significantly less than observed market trends. We continue to believe that the previous analysis is valid for today's action and that the result of the 1998 economic impact analysis resulted in a very low percent increase in price and output changes. Therefore, we believe that imposition of regulatory costs associated with this final rule will result in negligible changes in natural gas prices, output, employment, foreign trade, and business closures.

D. What are the Non-Air Environmental and Energy Impacts?

The water impacts associated with the installation of a condenser system for the TEG dehydration unit reboiler vent would be minimal. This is because the condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal by reinjection.

Similarly, the water impacts associated with installation of a vapor control system would be minimal. This is because the water vapor collected along with the hydrocarbon vapors in the vapor collection and redirect system can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with the produced water for disposal for reinjection.

The best management practice of optimizing the glycol circulation rate would result in lower quantities of water being absorbed into the glycol and sent to the glycol dehydration unit.

Therefore, we expect the adverse water impacts from the implementation of the emissions reduction options for the final area source standards to be minimal.

We do not anticipate any adverse solid waste impacts from the implementation of the area source standards.

Energy impacts are those energy requirements associated with the operation of emission control devices. There would be no national energy demand increase from the operation of any of the control options analyzed under the final oil and natural gas production standards for area sources. The final area source standards encourage the use of emission controls that recover hydrocarbon products, such as methane and condensate that can be used on-site as fuel or reprocessed, within the production process, for sale. There are no energy requirements associated with the management

practices within this final rule. Thus, the final standards have a positive impact associated with the recovery of non-renewable energy resources.

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." This action meets criteria 3(f)(4) of Executive Order 12866, "raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order." 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 information collection requirements in this rule 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 area source provisions of the Oil and Natural Gas Production NESHAP are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions in 40 CFR part 63, subpart A, which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to EPA policies set forth in 40 CFR part 2, subpart B.

This final rule requires maintenance inspections of the control devices but does not require any notifications or reports beyond those required by the applicable General Provisions in subpart A to 40 CFR part 63. The recordkeeping requirements require only the specific information needed to determine compliance.

The Oil and Natural Gas Production NESHAP requires that facility owners or operators retain records for a period of 5 years, which exceeds the 3-year retention period contained in the guidelines in 5 CFR 1320.6. The 5-year retention period is consistent with the provisions of the General Provisions of 40 CFR part 63, and with the 5-year records retention requirement in the operating permit program under title V of the CAA. All subsequent guidelines have been followed and do not violate any of the Paperwork Reduction Act guidelines contained in 5 CFR 1320.6.

The annual projected burden for this information collection to owners and operators of affected sources subject to the emissions reduction requirements in this final rule (averaged over the first 3 years after the effective date of the promulgated rule) is estimated to be 28,000 labor-hours per year, with a total annual cost of $1.6 million per year. These estimates include a one-time performance test and report (with repeat tests where needed), preparation of a startup, shutdown, and malfunction plan, immediate reports for any event when the procedures in the plan were not followed, annual compliance reports, maintenance inspections, notifications, and recordkeeping.

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 Information Collection Request 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 impacts of today's rule on small entities, small entity is defined as: (1) A small business with 500 employees or less (as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's final rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. This final rule requires emission reductions (either by installing a control device or by implementing management practices) at facilities that operate a TEG dehydration unit with an average annual natural gas throughput at or above 85 thousand m3/day (3 MMSCF/D) and benzene emissions at or above 0.90 Mg/yr (1.0 tpy). This final rule provides that GACT is no control for sources with natural gas flow below 85 thousand m3/day (3 MMSCF/D) or with benzene emissions below 0.90 Mg/yr (1.0 tpy) of benzene. Accordingly, we estimated that 2,222 of the 38,000 sources would be subject to the emission reduction requirements.

We performed an economic impact analysis to estimate the changes in product price and production quantities due to this final rule. Because sales and revenues data were not readily available for the affected industries, we began our analysis by examining the annual cost of meeting the emissions reduction requirements. Since the maximum cost incurred by a source subject to this final rule occurs when installing add-on controls, we are basing our analysis on that compliance approach. The annual per unit cost of compliance with this final rule would be $17,657. The throughput cost for natural gas has experienced significant volatility within the past several years, making a point estimate difficult to identify. The wellhead natural gas price, from the Department of Energy, averaged $4.00 per thousand cubic feet from 2001 to 2003. In order to be conservative for this analysis, we assumed a natural gas price of $88.29 per thousand cubic meters ($2.50 per thousand cubic feet).

One frequently used approach for determining whether or not a rule would have a significant impact on a small entity is to compare annualized control cost with annualized revenue from sales. Typically, costs less than 1 percent of revenues are not considered as imposing a significant impact. In the present case, the annual per-unit cost of compliance is estimated to be $17,657. Using the aforementioned 1 percent criterion for significant impact, annual revenues would have to be less than $1,765,700 in order for significant impact to occur. At $88.29 per thousand cubic meters ($2.50 per thousand cubic feet) of throughput, that revenue translates to 19,999 thousand cubic meters per year (706,280 thousand cubic feet per year) throughput, or 54.8 thousand m3/day (1.94 MMSCF/D). Since the cutoff for installation of emissions controls for this final rule is 85 thousand m3/day (3 MMSCF/D), we determined the annual cost of control for those entities affected by this final rule is not sufficient to generate a significant impact on a substantial number of small entities.

Although this final rule will not have a significant economic impact on a substantial number of small entities, we nonetheless have tried to reduce the impact of this rule on small entities. Where periodic reporting is required, we are requiring annual reporting in this rule, as opposed to semi-annual reporting that is required in the major source NESHAP for this category. In addition, our subcategorization, as described above, should reduce the number of small entities impacted and the extent of the impact.

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 this 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 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 1 year. The maximum total annual cost of this final rule for any 1 year has been estimated to be less than $2.5 million. Thus, today's rule is not subject to the requirements of sections 202 and 205 of the UMRA. In addition, the rule does not significantly or uniquely affect small governments because it does not contain any requirements applicable to such governments or impose obligations upon them. Therefore, today's rule is not subject to 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."

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. 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.

This final rule does not significantly or uniquely affect the communities of Indian tribal governments. We do not know of any area source TEG dehydration units owned or operated by Indian tribal governments. However, if there are any, the effect of this final rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to this final rule.

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

Executive Order 13045: "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 Order has the potential to influence the regulation. This final rule is not subject to Executive Order 13045 because it is 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 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. Further, we have concluded that this rule is not likely to have any adverse energy effects.

I. National Technology Transfer and Advancement Act

As noted in the proposed rule, Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs 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 action does not involve technical standards. Therefore, EPA did not consider the use of any VCS. However, we would like to note that the draft standard ASTM Z7420Z, which was cited in the final Oil and Natural Gas Production NESHAP (64 FR 32609–32664, June 17, 1999) as a potentially practical method to use in lieu of EPA Method 18, has now been finalized by ASTM and approved by EPA for use in rules where Method 18 is cited. This new standard is ASTM D6420–99 (2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, and it is appropriate for inclusion in this final rule in addition to EPA Method 18, codified at 40 CFR part 60, appendix A, for measurement of total organic carbon, total HAP, total volatile HAP, and benzene.

Similar to EPA's performance-based Method 18, ASTM D6420–99 (2004) is also a performance-based method for measurement of total gaseous organic compounds. However, ASTM D6420–99 (2004) was written to support the specific use of highly portable and automated gas chromatographs/mass spectrometers (GC/MS). While offering advantages over the traditional Method 18, the ASTM method does allow some less stringent criteria for accepting GC/MS results than required by Method 18. Therefore, ASTM D6420–99 (2004) is a suitable alternative to Method 18 only where: (1) The target compound(s) are those listed in Section 1.1 of ASTM D6420–99 (2004), 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 (2004), but potentially detected by mass spectrometry, this final rule 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 (2004), and not amenable to detection by mass spectrometry, ASTM D6420–99 (2004) does not apply.

As a result, EPA will allow ASTM D6420–99 (2004) for use with this final rule. The EPA will also allow Method 18 as an option in addition to ASTM D6420–99 (2004). This will allow the continued use of GC configurations other than GC/MS. Under 40 CFR 63.7(f) and 40 CFR 63.8(f), subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures.

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 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 United States Senate, the United States 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 January 3, 2007.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Incorporation by reference, Reporting and recordkeeping requirements.

Dated: December 21, 2006.

Stephen L. Johnson,

Administrator.

■ For the reasons set forth in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

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

Subpart A—[Amended]

■ 2. 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), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectometry, IBR approved for §§ 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).

* * * * *

Subpart HH—[Amended]

■ 3. Section 63.760 is amended as follows:

■ a. By revising paragraph (a)(1) introductory text;

■ b. By revising paragraph (b);

■ c. By revising paragraph (e)(2);

■ d. By revising paragraph (f) introductory text;

■ e. By revising the first sentences in paragraphs (f)(1) and (f)(2);

■ f. By adding paragraphs (f)(3) through (6);

■ g. By revising paragraph (g) introductory text; and

■ h. By adding a sentence at the end of paragraph (h).

§ 63.760 Applicability and designation of affected source.

(a) * * *

(1) Facilities that are major or area sources of hazardous air pollutants (HAP) as defined in § 63.761. Emissions for major source determination purposes can be estimated using the maximum natural gas or hydrocarbon liquid throughput, as appropriate, calculated in paragraphs (a)(1)(i) through (iii) of this section. As an alternative to calculating the maximum natural gas or hydrocarbon liquid throughput, the owner or operator of a new or existing source may use the facility's design maximum natural gas or hydrocarbon

liquid throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction. A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels (without first obtaining and complying with other limitations that keep its potential to emit HAP below major source levels), and becomes a major source, must comply thereafter with all provisions of this subpart applicable to a major source starting on the applicable compliance date specified in paragraph (f) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

* * * * *

(b) The affected sources for major sources are listed in paragraph (b)(1) of this section and for area sources in paragraph (b)(2) of this section.

(1) For major sources, the affected source shall comprise each emission point located at a facility that meets the criteria specified in paragraph (a) of this section and listed in paragraphs (b)(1)(i) through (b)(1)(iv) of this section.

(i) Each glycol dehydration unit;

(ii) Each storage vessel with the potential for flash emissions;

(iii) The group of all ancillary equipment, except compressors, intended to operate in volatile hazardous air pollutant service (as defined in § 63.761), which are located at natural gas processing plants; and

(iv) Compressors intended to operate in volatile hazardous air pollutant service (as defined in § 63.761), which are located at natural gas processing plants.

(2) For area sources, the affected source includes each triethylene glycol (TEG) dehydration unit located at a facility that meets the criteria specified in paragraph (a) of this section.

* * * * *

(e) * * *

(2) A major source facility, prior to the point of custody transfer, with a facility-wide actual annual average natural gas throughput less than 18.4 thousand standard cubic meters per day and a facility-wide actual annual average hydrocarbon liquid throughput less than 39,700 liters per day.

(f) The owner or operator of an affected major source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(1) and (f)(2) of this section. The owner or operator of an affected area source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(3) through (f)(6) of this section.

(1) The owner or operator of an affected major source, the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with the applicable provisions of this subpart no later than June 17, 2002, except as provided for in § 63.6(i). * * *

(2) The owner or operator of an affected major source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the applicable provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later.* * *

(3) The owner or operator of an affected area source, located in an Urban-1 county, as defined in § 63.761, the construction or reconstruction of which commences before February 6, 1998, shall achieve compliance with the provisions of this subpart no later than the dates specified in paragraphs (f)(3)(i) or (ii) of this section, except as provided for in § 63.6(i).

(i) If the affected area source is located within any UA plus offset and UC boundary, as defined in § 63.761, the compliance date is January 4, 2010.

(ii) If the affected area source is not located within any UA plus offset and UC boundary, as defined in § 63.761, the compliance date is January 5, 2009.

(4) The owner or operator of an affected area source, located in an Urban-1 county, as defined in § 63.761, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the provisions of this subpart immediately upon initial startup or January 3, 2007, whichever date is later.

(5) The owner or operator of an affected area source that is not located in an Urban-1 county, as defined in § 63.761, the construction or reconstruction of which commences before July 8, 2005, shall achieve compliance with the provisions of this subpart no later than the dates specified in paragraphs (f)(5)(i) or (ii) of this section, except as provided for in § 3.6(i).

(i) If the affected area source is located within any UA plus offset and UC boundary, as defined in § 63.761, the compliance date is January 4, 2010.

(ii) If the affected area source is not located within any UA plus offset and UC boundary, as defined in § 63.761, the compliance date is January 5, 2009.

(6) The owner or operator of an affected area source that is not located in an Urban-1 county, as defined in § 63.761, the construction or reconstruction of which commences on or after July 8, 2005, shall achieve compliance with the provisions of this subpart immediately upon initial startup or January 3, 2007, whichever date is later.

* * * * *

(g) The following provides owners or operators of an affected source at a major source with information on overlap of this subpart with other regulations for equipment leaks. The owner or operator of an affected source at a major source shall document that they are complying with other regulations by keeping the records specified in § 63.774(b)(9).

* * * * *

(h) * * * Unless otherwise required by law, the owner or operator of an area source subject to the provisions of this subpart is exempt from the permitting requirements established by 40 CFR part 70 or 40 CFR part 71.

■ 4. Section 63.761 is amended by adding, in alphabetical order, the definitions of "UA plus offset and UC," "Urban-1 County," "urbanized area," and "urban cluster" to read as follows:

§ 63.761 Definitions.

* * * * *

UA plus offset and UC is defined as the area occupied by each urbanized area, each urban cluster that contains at least 10,000 people, and the area located two miles or less from each urbanized area boundary.

Urban-1 County is defined as a county that contains a part of a Metropolitan Statistical Area with a population greater than 250,000, based on the Office of Management and Budget's *Standards for defining Metropolitan and Micropolitan Statistical Areas* (December 27, 2000), and Census 2000 Data released by the U.S. Census Bureau.

Urbanized area refers to Census 2000 Urbanized Area, which is defined in the *Urban Area Criteria for Census 2000* (March 15, 2002). Essentially, an urbanized area consists of densely settled territory with a population of at least 50,000 people.

Urban cluster refers to a Census 2000 Urban Cluster, which is defined in the *Urban Area Criteria for Census 2000* (March 15, 2002). Essentially, an urban cluster consists of densely settled

territory with at least 2,500 people but fewer than 50,000 people.

* * * * *

■ 5. Section 63.762 is amended by revising paragraph (e) to read as follows:

§ 63.762 Startups, shutdowns, and malfunctions.

* * * * *

(e) Owners or operators are not required to prepare a startup, shutdown, and malfunction plan for any facility where all of the affected sources meet the exemption criteria specified in § 63.764(e), or for any facility that is not located within a UA plus offset and UC boundary.

■ 6. Section 63.764 is amended by adding paragraph (d) and by revising paragraph (e)(1) introductory text to read as follows:

§ 63.764 General standards.

* * * * *

(d) Except as specified in paragraph (e)(1) of this section, the owner or operator of an affected source located at an existing or new area source of HAP emissions shall comply with the applicable standards specified in paragraph (d) of this section.

(1) Each owner or operator of an area source located within an UA plus offset and UC boundary (as defined in § 63.761) shall comply with the provisions specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) The control requirements for glycol dehydration unit process vents specified in § 63.765;

(ii) The monitoring requirements specified in § 63.773; and

(iii) The recordkeeping and reporting requirements specified in §§ 63.774 and 63.775.

(2) Each owner or operator of an area source not located in a UA plus offset and UC boundary (as defined in § 63.761) shall comply with paragraphs (d)(2)(i) through (iii) of this section.

(i) Determine the optimum glycol circulation rate using the following equation:

$$L_{OPT} = 1.15 * 3.0 \frac{\text{gal TEG}}{\text{lb } H_2O} * \left(\frac{F * (I - O)}{24 \text{ hr/day}} \right)$$

Where:

L_{OPT} = Optimal circulation rate, gal/hr.
F = Gas flowrate (MMSCF/D).
I = Inlet water content (lb/MMSCF).
O = Outlet water content (lb/MMSCF).
3.0 = The industry accepted rule of thumb for a TEG-to water ratio (gal TEG/lb H_2O).
1.15 = Adjustment factor included for a margin of safety.

(ii) Operate the TEG dehydration unit such that the actual glycol circulation rate does not exceed the optimum glycol circulation rate determined in accordance with paragraph (d)(2)(i) of this section. If the TEG dehydration unit is unable to meet the sales gas specification for moisture content using the glycol circulation rate determined in accordance with paragraph (d)(2)(i), the owner or operator must calculate an alternate circulation rate using GRI–GLYCalc™, Version 3.0 or higher. The owner or operator must document why the TEG dehydration unit must be operated using the alternate circulation rate and submit this documentation with the initial notification in accordance with § 63.775(c)(7).

(iii) Maintain a record of the determination specified in paragraph (d)(2)(ii) in accordance with the requirements in § 63.774(f) and submit the Initial Notification in accordance with the requirements in § 63.775(c)(7). If operating conditions change and a modification to the optimum glycol circulation rate is required, the owner or operator shall prepare a new determination in accordance with paragraph (d)(2)(i) or (ii) of this section and submit the information specified under § 63.775(c)(7)(ii) through (v).

(e) * * *

(1) The owner or operator is exempt from the requirements of paragraph (c)(1) and (d) of this section if the criteria listed in paragraph (e)(1)(i) or (ii) of this section are met, except that the records of the determination of these criteria must be maintained as required in § 63.774(d)(1).

* * * * *

■ 7. Section 63.765 is amended by revising paragraph (a) to read as follows:

§ 63.765 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart with an actual annual average natural gas flowrate equal to or greater than 85 thousand standard cubic meters per day and with actual average benzene glycol dehydration unit process vent emissions equal to or greater than 0.90 megagrams per year, that must be controlled for HAP emissions as specified in either paragraph (c)(1)(i) or paragraph (d)(1)(i) of § 63.764.

* * * * *

■ 8. Section 63.772 is amended as follows:

■ a. By revising paragraph (a)(1);

■ b. By revising the first sentence of paragraph (b)(2)(ii);

■ c. By revising paragraph (e)(3)(iii) introductory text;

■ d. By revising paragraph (e)(3)(iii)(B)(*2*); and

■ e. By revising the first and second sentences of paragraph (e)(3)(iv) introductory text.

§ 63.772 Test methods, compliance procedures, and compliance demonstrations.

(a) * * *

(1) For a piece of ancillary equipment and compressors to be considered not in VHAP service, it must be determined that the percent VHAP content can be reasonably expected never to exceed 10.0 percent by weight. For the purposes of determining the percent VHAP content of the process fluid that is contained in or contacts a piece of ancillary equipment or compressor, you shall use the method in either paragraph (a)(1)(i) or paragraph (a)(1)(ii) of this section.

(i) Method 18 of 40 CFR part 60, appendix A, or

(ii) ASTM D6420–99 (2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference—see § 63.14), provided that the provisions of paragraphs (a)(1)(ii)(A) through (D) of this section are followed:

(A) The target compound(s) are those listed in section 1.1 of ASTM D6420–99 (2004);

(B) The target concentration is between 150 parts per billion by volume and 100 parts per million by volume;

(C) For target compound(s) not listed in Table 1.1 of ASTM D6420–99 (2004), but potentially detected by mass spectrometry, the additional system continuing calibration check after each run, as detailed in section 10.5.3 of ASTM D6420–99 (2004), is conducted, met, documented, and submitted with the data report, even if there is no moisture condenser used or the compound is not considered water soluble; and

(D) For target compound(s) not listed in Table 1.1 of ASTM D6420–99 (2004), and not amenable to detection by mass spectrometry, ASTM D6420–99 (2004) may not be used.

* * * * *

(b) * * *

(2) * * * (ii) The owner or operator shall determine an average mass rate of benzene emissions in kilograms per hour through direct measurement using the methods in § 63.772(a)(1)(i) or (ii), or an alternative method according to § 63.7(f).* * *

* * * * *

(e) * * *

(3) * * *

(iii) To determine compliance with the control device percent reduction performance requirement in

§ 63.771(d)(1)(i)(A), (d)(1)(ii), and (e)(3)(ii), the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; Method 25A, 40 CFR part 60, appendix A; ASTM D6420–99 (2004), as specified in § 63.772(a)(1)(ii); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate percent reduction efficiency:

* * * * *

(B) * * *

(*2*) When the TOC mass rate is calculated, all organic compounds (minus methane and ethane) measured by Method 18, 40 CFR part 60, appendix A, or Method 25A, 40 CFR part 60, appendix A, or ASTM D6420–99 (2004) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (e)(3)(iii)(B)(*1*) of this section.

* * * * *

(iv) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.771(d)(1)(i)(B), the owner or operator shall use one of the following methods to measure either TOC (minus methane and ethane) or total HAP: Method 18, 40 CFR part 60, appendix A; Method 25A, 40 CFR part 60, appendix A; ASTM D6420–99 (2004), as specified in § 63.772(a)(1)(ii), or any other method or data that have been validated according to Method 301 of appendix A of this part.* * *

* * * * *

■ 9. Section 63.774 is amended as follows:

■ a. By revising paragraph (b) introductory text;

■ b. By revising paragraph (d)(1) introductory text; and

■ c. By adding paragraph (f).

§ 63.774 Recordkeeping requirements.

* * * * *

(b) Except as specified in paragraphs (c), (d), and (f) of this section, each owner or operator of a facility subject to this subpart shall maintain the records specified in paragraphs (b)(1) through (11) of this section:

* * * * *

(d)(1) An owner or operator of a glycol dehydration unit that meets the exemption criteria in § 63.764(e)(1)(i) or § 63.764(e)(1)(ii) shall maintain the records specified in paragraph (d)(1)(i) or paragraph (d)(1)(ii) of this section, as appropriate, for that glycol dehydration unit.

* * * * *

(f) The owner or operator of an area source not located within a UA plus offset and UC boundary must keep a record of the calculation used to determine the optimum glycol circulation rate in accordance with § 63.764(d)(2)(i) or § 63.764(d)(2)(ii), as applicable.

■ 10. Section 63.775 is amended as follows:

■ a. By adding paragraph (c);

■ b. By revising paragraph (e) introductory text; and

■ c. By adding paragraph (e)(3).

§ 63.775 Reporting requirements.

* * * * *

(c) Except as provided in paragraph (c)(8), each owner or operator of an area source subject to this subpart shall submit the information listed in paragraph (c)(1) of this section. If the source is located within a UA plus offset and UC boundary, the owner or operator shall also submit the information listed in paragraphs (c)(2) through (6) of this section. If the source is not located within any UA plus offset and UC boundaries, the owner or operator shall also submit the information listed within paragraph (c)(7).

(1) The initial notifications required under § 63.9(b)(2) not later than January 3, 2008. In addition to submitting your initial notification to the addressees specified under § 63.9(a), you must also submit a copy of the initial notification to EPA's Office of Air Quality Planning and Standards. Send your notification via e-mail to *CCG–ONG@EPA.GOV* or via U.S. mail or other mail delivery service to U.S. EPA, Sector Policies and Programs Division/Coatings and Chemicals Group (E143–01), Attn: Oil and Gas Project Leader, Research Triangle Park, NC 27711.

(2) The date of the performance evaluation as specified in § 63.8(e)(2) if an owner or operator is required by the Administrator to conduct a performance evaluation for a continuous monitoring system.

(3) The planned date of a performance test at least 60 days before the test in accordance with § 63.7(b). Unless requested by the Administrator, a site-specific test plan is not required by this subpart. If requested by the Administrator, the owner or operator must submit the site-specific test plan required by § 63.7(c) with the notification of the performance test. A separate notification of the performance test is not required if it is included in the initial notification submitted in accordance with paragraph (c)(1) of this section.

(4) A Notification of Compliance Status as described in paragraph (d) of this section;

(5) Periodic reports as described in paragraph (e)(3) of this section; and

(6) Startup, shutdown, and malfunction reports specified in § 63.10(d)(5). Separate startup, shutdown, and malfunction reports as described in § 63.10(d)(5) are not required if the information is included in the Periodic Report specified in paragraph (e) of this section.

(7) The information listed in paragraphs (c)(1)(i) through (v) of this section. This information shall be submitted with the initial notification.

(i) Documentation of the source's location relative to the nearest UA plus offset and UC boundaries. This information shall include the latitude and longitude of the affected source; whether the source is located in an urban cluster with 10,000 people or more; the distance in miles to the nearest urbanized area boundary if the source is not located in an urban cluster with 10,000 people or more; and the names of the nearest urban cluster with 10,000 people or more and nearest urbanized area.

(ii) Calculation of the optimum glycol circulation rate determined in accordance with § 63.764(d)(2)(i).

(iii) If applicable, documentation of the alternate glycol circulation rate calculated using GRI-GLYCalc™, Version 3.0 or higher and documentation stating why the TEG dehydration unit must operate using the alternate glycol circulation rate.

(iv) The name of the manufacturer and the model number of the glycol circulation pump(s) in operation.

(v) Statement by a responsible official, with that official's name, title, and signature, certifying that the facility will always operate the glycol dehydration unit using the optimum circulation rate determined in accordance with § 63.764(d)(2)(i) or § 63.764(d)(2)(ii), as applicable.

(8) An owner or operator of a TEG dehydration unit located at an area source that meets the criteria in § 63.764(e)(1)(i) or § 63.764(e)(1)(ii) is exempt from the reporting requirements for area sources in paragraphs (c)(1) through (7) of this section, for that unit.

* * * * *

(e) *Periodic Reports.* An owner or operator of a major source shall prepare Periodic Reports in accordance with paragraphs (e) (1) and (2) of this section and submit them to the Administrator. An owner or operator of an area source shall prepare Periodic Reports in accordance with paragraph (e)(3) of this section and submit them to the Administrator.

* * * * *

(3) An owner or operator of an area source located inside a UA plus offset

and UC boundary shall prepare and submit Periodic Reports in accordance with paragraphs (e)(3)(i) through (iii) of this section.

(i) Periodic reports must be submitted on an annual basis. The first reporting period shall cover the period beginning on the date the Notification of Compliance Status Report is due and ending on December 31. The report shall be submitted within 30 days after the end of the reporting period.

(ii) Subsequent reporting periods begin every January 1 and end on December 31. Subsequent reports shall be submitted within 30 days following the end of the reporting period.

(iii) The periodic reports must contain the information included in paragraph (e)(2) of this section.

* * * * *

■ 11. In the Appendix to Subpart HH of Part 63, revise Table 2 to read as follows:

Appendix to Subpart HH of Part 63—Tables

* * * * *

TABLE 2 TO SUBPART HH OF PART 63.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH

General provisions reference	Applicable to subpart HH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6)	Yes.	
§ 63.1(a)(7) through (a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12)	Yes.	
§ 63.1(b)(1)	No	Subpart HH specifies applicability.
§ 63.1(b)(2)	No	Section reserved.
§ 63.1(b)(3)	Yes.	
§ 63.1(c)(1)	No	Subpart HH specifies applicability.
§ 63.1(c)(2)	Yes.	Subpart HH exempts area sources from the requirement to obtain a title V permit unless otherwise required by law as specified in § 63.760(h).
§ 63.1(c)(3) and (c)(4)	No	Section reserved.
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes.	Except definition of major source is unique for this source category and there are additional definitions in subpart HH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1) through (a)(2)	Yes.	
§ 63.4(a)(3) through (a)(5)	No	Section reserved.
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	Yes.	
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	No	Section Reserved.
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) through (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.6(e)(1)(i)	No	Except as otherwise specified. Addressed in § 63.762.
§ 63.6(e)(1)(ii)	Yes.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	No	Section reserved.
§ 63.6(e)(3)(i)	Yes.	Sources exempt under § 63.764(e) and sources located outside UA plus offset and UC boundaries are not required to develop startup, shutdown, and malfunction plans as stated in § 63.762(e).
§ 63.6(e)(3)(i)(A)	No	Except as otherwise specified. Addressed in § 63.762(c).
§ 63.6(e)(3)(i)(B)	Yes.	
§ 63.6(e)(3)(i)(C)	Yes.	
§ 63.6(e)(3)(ii)	No	Section reserved.
§ 63.6(e)(3)(iii) through (3)(vi)	Yes.	
§ 63.6(e)(3)(vii)	Yes.	
§ 63.6(e)(3)(vii) (A)	Yes.	
§ 63.6(e)(3)(vii) (B)	Yes	Except that the plan must provide for operation in compliance with § 63.762(c).
§ 63.6(e)(3)(viii) through (ix)	Yes.	
§ 63.6(f)(1)	Yes.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	
§ 63.6(h)	No	Subpart HH does not contain opacity or visible emission standards.
§ 63.6(i)(1) through (i)(14)	Yes.	
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(b)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	Yes.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	Yes.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	Yes.	
§ 63.8(c)(4)(i)	No	Subpart HH does not require continuous opacity monitors.
§ 63.8(c)(4)(ii)	Yes.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)	Yes.	
§ 63.8(e)	Yes	Subpart HH does not specifically require continuous emissions monitor performance evaluation, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	Yes.	
§ 63.8(g)	No	Subpart HH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification. Major and area sources that meet § 63.764(e) do not have to submit initial notifications.
§ 63.9(b)(3)	No	Section reserved.
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	No	Subpart HH does not have opacity or visible emission standards.
§ 63.9(g)(1)	Yes.	
§ 63.9(g)(2)	No	Subpart HH does not have opacity or visible emission standards.
§ 63.9(g)(3)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit notifications of compliance status.
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) through (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes.	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data on site and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	
§ 63.10(b)(3)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data on site and allows offsite storage for the remaining 4 years of data.
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.
§ 63.10(c)(10) through(c)(15)	Yes.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes	Area sources located outside UA plus offset and UC boundaries do not have to submit performance test reports.
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)(i)	Yes	Subpart HH requires major sources to submit a startup, shutdown, and malfunction report semi-annually. Area sources located within UA plus offset and UC boundaries are required to submit startup, shutdown, and malfunction reports annually. Area sources located outside UA plus offset and UC boundaries are not required to submit startup, shutdown, and malfunction reports.
§ 63.10(e)(1)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(2)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)	Yes	Subpart HH requires major sources to submit Periodic Reports semi-annually. Area sources are required to submit Periodic Reports annually. Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No	Section reserved.
§ 63.10(e)(3)(ii) through (viii)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) and (b)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) and (b)	Yes.	
§ 63.15(a) and (b)	Yes	
§ 63.16	Yes.	

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 261

[SW–FRL–8264–7]

Hazardous Waste Management System; Identification and Listing of Hazardous Waste; Final Exclusion

AGENCY: Environmental Protection Agency.

ACTION: Final Rule.

SUMMARY: Environmental Protection Agency (EPA) is granting a petition submitted by General Motors Corporation-Arlington Truck Assembly Plant (GM-Arlington) to exclude (or delist) a wastewater treatment plant (WWTP) sludge generated by GM-Arlington in Arlington, TX from the lists of hazardous wastes. This final rule responds to the petition submitted by GM-Arlington to delist F019 WWTP sludge generated from the facility's waste water treatment plant.

After careful analysis and use of the Delisting Risk Assessment Software (DRAS), EPA has concluded the petitioned waste is not hazardous waste. This exclusion applies to 3,000 cubic yards per year of the F019 WWTP sludge. Accordingly, this final rule excludes the petitioned waste from the requirements of hazardous waste regulations under the Resource Conservation and Recovery Act (RCRA) when it is disposed in a Subtitle D Landfill.

EFFECTIVE DATE: January 3, 2007.

ADDRESSES: The public docket for this final rule is located at the Environmental Protection Agency Region 6, 1445 Ross Avenue, Dallas, Texas 75202, and is available for viewing in EPA Freedom of Information Act review room on the 7th floor from 9 a.m. to 4 p.m., Monday through Friday, excluding Federal holidays. Call (214) 665–6444 for appointments. The reference number for this docket is "F–05–TXDEL–GM-Arlington.". The public may copy material from any regulatory docket at no cost for the first 100 pages and at a cost of $0.15 per page for additional copies.

FOR FURTHER INFORMATION CONTACT: Ben Banipal, Section Chief of the Corrective Action and Waste Minimization Section, Multimedia Planning and Permitting Division (6PD–C), Environmental Protection Agency Region 6, 1445 Ross Avenue, Dallas, Texas 75202. For technical information concerning this notice, contact Youngmoo Kim, Environmental Protection Agency Region 6, 1445 Ross Avenue, (6PD–C), Dallas, Texas 75202, at (214) 665–6788, or *kim.youngmoo@epa.gov.*

SUPPLEMENTARY INFORMATION: The information in this section is organized as follows:

I. Overview Information
  A. What action is EPA finalizing?
  B. Why is EPA approving this action?
  C. What are the limits of this exclusion?
  D. How will GM-Arlington manage the waste if it is delisted?
  E. When is the final delisting exclusion effective?
  F. How does this final rule affect states?
II. Background
  A. What is a delisting?
  B. What regulations allow facilities to delist a waste?
  C. What information must the generator supply?
III. EPA's Evaluation of the Waste Information and Data
  A. What waste did GM-Arlington petition EPA to delist?
  B. How much waste did GM-Arlington propose to delist?
  C. How did GM-Arlington sample and analyze the waste data in this petition?
IV. Public Comments Received on the proposed exclusion
  A. Who submitted comments on the proposed rule?
  B. What were the comments and what are EPA's responses to them?
V. Statutory and Executive Order Reviews

I. Overview Information

A. What action is EPA finalizing?

After evaluating the petition, EPA proposed, on July 19, 2005, to exclude the waste water treatment plant sludge from the lists of hazardous waste under 40 CFR 261.31 and 261.32 (see 70 FR 41358). EPA is finalizing the decision to grant GM-Arlington's delisting petition to have its waste water treatment sludge managed and disposed as non-hazardous waste provided certain verification and monitoring conditions are met.

B. Why is EPA approving this action?

GM-Arlington's petition requests a delisting from the F019 waste listing under 40 CFR 260.20 and 260.22. GM-Arlington does not believe that the petitioned waste meets the criteria for which EPA listed it. GM-Arlington also believes no additional constituents or factors could cause the waste to be hazardous. EPA's review of this petition included consideration of the original listing criteria and the additional factors required by the Hazardous and Solid Waste Amendments of 1984. See section 3001(f) of RCRA, 42 U.S.C. 6921(f), and 40 CFR 260.22 (d)(1)–(4) (hereinafter all sectional references are to 40 CFR unless otherwise indicated). In making the final delisting determination, EPA evaluated the petitioned waste against the listing criteria and factors cited in § 261.11(a)(2) and (a)(3). Based on this review, EPA agrees with the petitioner that the waste is nonhazardous with respect to the original listing criteria. If EPA had found, based on this review, that the waste remained hazardous based on the factors for which the waste as originally listed, EPA would have proposed to deny the petition. EPA evaluated the waste with respect to other factors or criteria to assess whether there is a reasonable basis to believe that such additional factors could cause the waste to be hazardous. EPA considered whether the waste is acutely toxic, the concentration of the constituents in the waste, their tendency to migrate and to bioaccumulate, their persistence in the environment once released from the waste, plausible and specific types of management of the petitioned waste, the quantities of waste generated, and waste variability. EPA believes that the petitioned waste does not meet the listing criteria and thus should not be a listed waste. EPA's final decision to delist waste from GM-Arlington's facility is based on the information submitted in support of this rule, including descriptions of the wastes and analytical data from the Arlington, Texas facility.

C. What are the limits of this exclusion?

This exclusion applies to the waste described in the petition only if the requirements described in 40 CFR Part 261, Appendix IX, Table 1 and the conditions contained herein are satisfied.

D. How will GM-Arlington manage the waste if it is delisted?

The WWTP sludge from GM-Arlington will be disposed of in a RCRA Subtitle D landfill.

E. When is the final delisting exclusion effective?

This rule is effective January 3, 2007. The Hazardous and Solid Waste Amendments of 1984 amended Section 3010 of RCRA, 42 U.S.C. 6930(b)(1), allows rules to become effective less than six months after the rule is published when the regulated community does not need the six-month period to come into compliance. That is the case here because this rule reduces, rather than increases, the existing requirements for persons generating hazardous waste. This reduction in existing requirements also provides a

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[AD–FRL–6346–8]

RIN 2060–AE34

National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and National Emission Standards for Hazardous Air Pollutants: Natural Gas Transmission and Storage

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rules.

SUMMARY: These promulgated national emission standards for hazardous air pollutants (NESHAP) limit emissions of hazardous air pollutants (HAP) from oil and natural gas production and natural gas transmission and storage facilities. These final rules implement section 112 of the Clean Air Act (Act) and are based on the Administrator's determination that oil and natural gas production and natural gas transmission and storage facilities emit HAP identified on the EPA's list of 188 HAP.

The EPA estimates that approximately 69,000 megagrams per year (Mg/yr) of HAP are emitted from facilities in these source categories. The primary HAP emitted by the facilities covered by these final standards include benzene, toluene, ethyl benzene, mixed xylenes (collectively referred to as BTEX), and n-hexane. Benzene is carcinogenic and has also been shown to cause various adverse health effects other than cancer (i.e., noncancer effects). The other four HAP are not classified as carcinogens based on available information; however, exposures to these four HAP have been shown to cause various noncancer effects.

The EPA estimates that these promulgated NESHAP will reduce HAP emissions from major sources in the oil and natural gas production source category by 77 percent and from major sources in the natural gas transmission and storage source category by 95.0 percent.

EFFECTIVE DATE: This regulation is effective June 17, 1999. See **SUPPLEMENTARY INFORMATION** concerning judicial review.

ADDRESSES: *Docket.* A docket, No. A-94-04, containing information considered by the EPA in developing the promulgated standards for the oil and natural gas production and natural gas transmission and storage source categories, is available for public inspection between 8:00 a.m. and 5:30 p.m., Monday through Friday (except for Federal holidays) at the following address: U.S. Environmental Protection Agency, Air and Radiation Docket and Information Center (MC-6102), 401 M Street SW., Washington DC 20460, telephone: (202) 260-7548. The docket is located at the above address in Room M-1500, Waterside Mall. The promulgated regulations, background information document (BID) volumes 1 and 2, and other supporting information are available for inspection and copying. A reasonable fee may be charged for copying.

Responses to Comments Document. The responses to comments document for the promulgated standards may be obtained from the EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone (919) 541-2777, or from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22151, telephone (703) 605-6000 or (800) 553-6847 or via the Internet at www.fedworld.gov/ntis/ntishome.html. Please refer to "National Emissions Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage—Background Information for Final Standards: Summary of Public Comments and Responses" (EPA-453/R-99-004b, May 1999). The document contains the following: (1) a summary of all the public comments made on the proposed standards and the Administrator's responses to the comments and (2) a summary of the changes made to the standards since proposal. This document is also available for downloading from the Technology Transfer Network (see **SUPPLEMENTARY INFORMATION**).

FOR FURTHER INFORMATION CONTACT: For information concerning today's action, contact Mr. Greg Nizich, Waste and Chemical Processes Group (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone: (919) 541-3078; facsimile: (919) 541-0246; or electronically at: nizich.greg@epa.gov.

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Regulated categories and entities include:

Category	Examples of regulated entities
Industry	Condensate tank batteries, glycol dehydration units, natural gas processing plants, and natural gas transmission and storage facilities.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by these actions. This table lists the types of entities that the EPA is now aware could potentially be regulated by these actions. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated by these actions, you should carefully examine the applicability criteria in sections 63.760 and 63.1270 of the rules. If you have questions regarding the applicability of these actions to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Technology Transfer Network. This document, the final regulatory texts, and BID volumes 1 and 2 are available in Docket No. A-94-04 from the EPA's Air and Radiation Docket and Information Center (see **ADDRESSES**). They can also be accessed through the EPA's Technology Transfer Network (TTN) Internet web site at: http://www.epa.gov/ttn/oarpg.

Judicial Review. National emission standards for hazardous air pollutants for facilities in the oil and natural gas production and natural gas transmission and storage source categories were proposed in the **Federal Register** on February 6, 1998 (63 FR 6288). This **Federal Register** action announces the EPA's final decisions on the rules. Under section 307(b)(1) of the Act, judicial review of the NESHAP is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of these final rules. Under section 307(b)(2) of the Act, the requirements that are the subject of today's action may not be challenged later in civil or criminal proceedings brought by the EPA to enforce these requirements.

Preamble Outline. The following outline is provided to aid in reading the preamble to the promulgated oil and natural gas production and natural gas transmission and storage NESHAP.

I. Background
II. Summary of Considerations in Developing the Rules
  A. Purpose of the Regulations
  B. Technical Basis of the Regulations
  C. Stakeholder and Public Participation
III. Summary of Promulgated Standards
  A. Promulgated Standards for Oil and Natural Gas Production for Major Sources
  B. Promulgated Standards for Natural Gas Transmission and Storage for Major Sources
  C. Recordkeeping and Reporting Provisions
IV. Summary of Impacts
  A. HAP Emission Reductions
  B. Secondary Environmental Impacts
  C. Energy Impacts
  D. Cost Impacts

E. Economic Impacts
V. Significant Comments and Changes to the Proposed Standards
A. Definition of Facility
B. Definition of "Associated Equipment"
C. Applicability
D. Glycol Dehydration Unit Process Vent Standards
E. Storage Vessel Standards
F. Standards for Natural Gas Transmission and Storage
G. Monitoring, Recordkeeping, and Reporting Requirements
H. Cost and Economic Impacts
VI. Administrative Requirements
A. Docket
B. Paperwork Reduction Act
C. Executive Order 12866: A Significant Regulatory Action Determination
D. Regulatory Flexibility Act
E. Congressional Review Act
F. Unfunded Mandates Reform Act
G. Executive Order 12875: Enhancing the Intergovernmental Partnership
H. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks
I. Executive Order 13084: Consultation and Coordination with Indian Tribal Governments
J. National Technology Transfer and Advancement Act

The following conversions from metric to English units are provided to aid in reading the preamble to the promulgated oil and natural gas production and natural gas transmission and storage NESHAP.

Metric values	Equivalent English values
0.31 cubic meter per liter (m^3/liter)	1,750 standard cubic feet per barrel (ft^3/barrel).
39,700 liter/day	250 barrels per day (bpd).
79,500 liter/day	500 bpd.
0.90 Megagrams per year (Mg/yr)	1.0 ton per year (tpy).
18.4 thousand cubic meters per day (m^3/day)	650 thousand cubic feet per day (scf/day).
28.3 thousand m^3/day	1 million scf/day (MMscf/day).
85 thousand m^3/day	3 MMscf/day.
283 thousand m^3/day	10 MMscf/day.

I. Background

Section 112(b) of the Act lists 188 HAP and directs the EPA to develop rules to control all major and some area sources emitting HAP. On July 16, 1992 (57 FR 31576), the EPA published a list of major and area sources for which NESHAP are to be published (i.e., the source category list). Oil and natural gas production facilities were listed as a category of major sources.

The EPA included natural gas transmission and storage facilities in the proposed initial listing of source categories that was published in 1991. Comments received on the proposed initial list indicated that this source category did not contain major sources of HAP. As a result, natural gas transmission and storage facilities were not included as a distinct source category in the July 1992 final list of source categories of major sources of HAP.

During the development of the standards for the oil and natural gas production source category, information was obtained on glycol dehydration unit HAP emissions that are representative of both oil and natural gas production facilities and natural gas transmission and storage facilities. The information indicated that natural gas transmission and storage facilities have the potential to be major HAP sources. In addition, representatives of the natural gas transmission and storage source category stated to the EPA that there are major source glycol dehydration units in the source category. Therefore, the EPA amended the source category list on February 12, 1998 (63 FR 7155) to add natural gas transmission and storage as a major source category.

On February 6, 1998, the EPA also gave notice of its intention to add oil and natural gas production as an area source category (63 FR 6291), but did not amend the source category list to include such a category. In order to ensure that regulations applicable to the area source category are consistent with the Urban Air Toxics Strategy, to be implemented under section 112(k) of the Act, the EPA has deferred the regulation of oil and natural gas production facilities which are area sources until the Urban Air Toxics Strategy is finalized. The EPA expects this strategy to be finalized later this year.

II. Summary of Considerations in Developing the Rules

A. Purpose of the Regulations

The Act was developed, in part,

> * * * to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and productive capacity of its population [the Act, section 101(b)(1)].

Oil and natural gas production and natural gas transmission and storage facilities are major and area sources of HAP emissions. The EPA estimates that approximately 67,000 Mg/yr of HAP are emitted from facilities in the oil and natural gas production source category and 2,100 Mg/yr of HAP are emitted from facilities in the natural gas transmission and storage source category. The primary HAP associated with oil and natural gas that have been identified include BTEX and n-hexane. Exposure to these chemicals has been demonstrated to cause adverse health effects. The likelihood of these adverse health effects depends on the range of ambient concentrations and the amount, frequency, and duration of exposures. The ambient concentrations are influenced by source-specific characteristics such as emission rates and local meteorological conditions. Exposure and health impacts due to the ambient concentrations are dependent on multiple factors that affect human variability such as genetics, age, health status (e.g., the presence of pre-existing disease), lifestyle, location of residence, activity patterns, and other factors.

Benzene, one of the HAP associated with these NESHAP, is classified as a known human carcinogen based on convincing human evidence (such as observed increases in the incidence of leukemia in exposed workers), as well as supporting evidence from animal studies. In addition, short-term inhalation of high benzene levels may cause nervous system effects such as drowsiness, dizziness, headaches, and unconsciousness in humans. At even higher concentrations of benzene, exposure may cause death, while lower concentrations may irritate the skin, eyes, and upper respiratory tract. Long-term inhalation exposure to benzene may cause various disorders of the blood, and toxicity to the immune system. Reproductive disorders in women, as well as developmental effects in animals, have also been reported for benzene exposure.

Short-term inhalation of relatively high concentrations of toluene by humans may cause nervous system effects such as fatigue, sleepiness, headaches, and nausea, as well as

irregular heartbeat. Repeated exposure to high concentrations may cause additional nervous system effects, including incoordination, tremors, death of brain cells, involuntary eye movements, and may impair speech, hearing, and vision. Long-term exposure to toluene by humans has also been reported to irritate the skin, eyes, and respiratory tract, and to cause dizziness, headaches, and difficulty with sleep. Children whose mothers have been exposed to high levels of toluene before birth may suffer nervous system dysfunction, attention deficits, and minor face and limb defects. Inhalation of toluene by pregnant women may also increase the risk of spontaneous abortion. Not enough information exists to determine toluene's carcinogenic potential.

Short-term inhalation of high levels of ethyl benzene by humans may cause throat and eye irritation, chest constriction, and dizziness. Long-term inhalation of ethyl benzene by humans may cause blood disorders. Animal studies have reported blood, liver, and kidney effects associated with ethyl benzene inhalation. Birth defects have been reported in animals exposed via inhalation; whether these effects may occur in humans is not known. Not enough information exists concerning ethyl benzene to determine its carcinogenic potential.

Short-term inhalation of high levels of mixed xylenes (a mixture of three closely-related compounds) by humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects. Long-term inhalation of high levels of xylene in humans may result in nervous system effects such as headaches, dizziness, fatigue, tremors, and incoordination. Other reported effects include labored breathing, heart palpitation, severe chest pain, abnormal heart functioning, and possible effects on the blood and kidneys. Developmental effects have been reported in animals from xylene exposure via inhalation. Not enough information exists to determine the carcinogenic potential of mixed xylenes.

Short-term inhalation of high levels of n-hexane by humans may cause mild central nervous system effects (dizziness, giddiness, slight nausea, and headache) and irritation of the skin and mucous membranes. Long-term inhalation exposure to high levels of n-hexane by humans has been reported to cause nerve damage expressed as numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Reproductive effects have been reported in animals after inhalation exposure (testicular damage in rats). Not enough information exists concerning n-hexane to determine its carcinogenic potential.

The EPA estimates that the NESHAP will reduce HAP emissions from those impacted HAP emission points in the oil and natural gas production source category by 77 percent and will reduce HAP emissions from impacted glycol dehydration units in the natural gas transmission and storage source category by 95.0 percent.

B. Technical Basis of Regulations

Section 112 of the Act regulates stationary sources of HAP. Section 112(b) of the Act lists 188 chemicals, compounds or groups of chemicals as HAP. The EPA is directed by section 112 to regulate the emission of HAP from stationary sources by establishing national emission standards.

Section 112(a)(1) of the Act defines a major source as:

> * * * any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential-to-emit considering controls, in the aggregate 10 tons per year (tpy) or more of any HAP or 25 tpy or more of any combination of HAP.

An area source is defined as a stationary source that is not a major source.

For major sources, the statute requires the EPA to establish standards that reflect the maximum degree of reduction in HAP emissions through application of maximum achievable control technology (MACT). Further, the EPA is required to establish standards that are no less stringent than the level of control defined under section 112(d)(3) of the Act, often referred to as the MACT floor. The final standards for major sources in the oil and natural gas production and natural gas transmission and storage source categories are based on the MACT floor for these source categories.

Prior to proposal, information on industry processes and operations, HAP emission points, and HAP emission reduction techniques were collected through section 114 questionnaires that were distributed to companies in the oil and natural gas production and natural gas transmission and storage source categories. These companies provided information on their representative facilities.

This information was used, in part, as the technical basis for determining the MACT level of control for the emission points covered under the final standards. In addition to information collected in the questionnaires, the EPA considered information available in the general literature, information submitted by industry on technical issues subsequent to the questionnaire responses, and additional information received during the public comment period for the proposed rules, in developing the final rules.

C. Stakeholder and Public Participation

In the development of these final standards, numerous representatives of the oil and natural gas production industry, the natural gas transmission and storage industry, and other interested parties were consulted. Industry representatives assisted in data gathering, arranging site visits, technical review, and sharing of industry-sponsored data collection activities. A data base comprised of all industry-supplied information was developed for evaluating HAP emissions and air emission controls for the final standards.

The standards for the oil and natural gas production and natural gas transmission and storage source categories were proposed in the **Federal Register** on February 6, 1998 (63 FR 6288). The preamble to the proposed standards described the rationale for the proposed standards. Public comments were solicited at the time of proposal. To provide interested parties the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was offered at proposal. However, the public did not request a hearing and, therefore, one was not held. The public comment period was from February 6, 1998 to April 7, 1998. Fifty comment letters were received. Commenters included industry representatives, trade associations, State agencies, and other interested parties.

On January 15, 1999, in response to comments received on the proposal, the EPA also published a supplemental notice announcing the availability of additional data collected from facilities in the natural gas transmission and storage source category (64 FR 2611). Four comment letters were received from industry representatives and trade associations.

All of the comments were carefully considered and changes were made to the proposed standards when determined by the EPA to be appropriate. A detailed discussion of these comments and responses can be found in a document entitled "National Emissions Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage—Background Information for Final Standards: Summary of Public Comments and Responses" (BID volume 2), which is

referenced in the **ADDRESSES** section of this preamble (EPA-453/R/99-004b, May 1999). The summary of comments and responses in the BID volume 2 serves as the basis for the revisions that have been made to the standards between proposal and promulgation. Section V of this preamble discusses the major changes.

III. Summary of Promulgated Standards

A. Promulgated Standards for Oil and Natural Gas Production for Major Sources

This final action amends title 40, chapter I, part 63 of the Code of Federal Regulations by adding a new Subpart HH—National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. The standards apply to owners and operators of facilities that process, upgrade, or store (1) hydrocarbon liquids (with the exception of those facilities that exclusively handle black oil) to the point of custody transfer and (2) natural gas from the well up to and including the natural gas processing plant. The standards limit HAP emissions from the following emission points at facilities that are major sources of HAP: (1) process vents on glycol dehydration units, (2) storage vessels with flash emissions, and (3) equipment leaks at natural gas processing plants.

As required by the Act, the determination of a facility's potential to emit HAP and, therefore, its status as a major source, is based on the total of all HAP emissions from all activities at a facility, except that section 112(n)(4) of the Act prohibits aggregating emissions from oil or gas exploration or production wells (and their associated equipment) and emissions from pipeline compressor or pump stations with emissions from other similar units. A definition of associated equipment is contained in the final standards.

To determine potential emissions for determining major source status, the final standards specify that an owner or operator that can document a decline in annual production each year for 5 years prior to the effective date of the rule must calculate the maximum facility throughput as the average of the annual throughput for the 3 years prior to the effective date of the rule, multiplied by 1.2. If any increase in production is observed over the 5 years prior to the effective date of the rule, the owner or operator must calculate the maximum facility throughput as the maximum annual throughput over the 5 years prior to the effective date times 1.2. The owner or operator must recalculate the maximum throughput if actual annual throughput increases to a rate above the calculated values. In addition, for other parameters used to estimate emissions, the owner or operator must use the maximum value measured over the period for which the maximum throughput is calculated and may be determined as an annual average or the highest single measured value.

1. Applicability

The final standards for oil and natural gas production facilities require that the owner or operator of a major source of HAP reduce HAP emissions from glycol dehydration units and storage vessels through the application of air emission control equipment or pollution prevention measures, or a combination of both. In addition, the owner or operator of a natural gas processing plant that is a major source of HAP is required to reduce HAP emissions from equipment leaks by establishing a leak detection and repair (LDAR) program.

The following are exempt from the requirements of subpart HH:

- Owners and operators of facilities that exclusively process, handle, and store black oil are not subject to the final standards. Black oil is defined in the final rule as a hydrocarbon liquid with an initial gas-to-oil ratio (GOR) less than 0.31 cubic meters per liter (m^3/liter) and an American Petroleum Institute (API) gravity less than 40 degrees. For this subpart, a facility that uses natural gas for fuel or generates gas from black oil still qualifies for this exemption.
- Oil and natural gas production facilities prior to the point of custody transfer that have a facilitywide actual annual average natural gas throughput less than 18.4 thousand cubic meters per day (m^3/day), and a facilitywide actual annual average hydrocarbon liquid throughput less than 39,700 liters per day (liter/day.) Oil and natural gas production facilities after the point of custody transfer, including natural gas processing plants, do not qualify for these exemptions.

2. Glycol Dehydration Unit Process Vent Standards

The MACT standard for process vents on new and existing glycol dehydration units was set at the floor level of control. To determine the MACT floor, the EPA divided glycol dehydration units into two sizes: (1) small glycol dehydration units with actual annual average natural gas throughputs less than 85 thousand m^3/day or with actual average benzene emissions less than 0.90 Mg/yr, and (2) large glycol dehydration units with actual annual average natural gas throughputs equal to or greater than 85 thousand m^3/day or with actual average benzene emissions equal to or greater than 0.90 Mg/yr. For small glycol dehydration units, the EPA determined that the MACT floor was no control and that it was not cost effective to select a regulatory alternative beyond the floor.

For large glycol dehydration units, the EPA reviewed the information that was available to develop a MACT floor (a detailed discussion of the development of the MACT floor can be found in the docket, Air Docket A-94-04). This information consisted of data gathered from: (1) industry responses to the EPA's Air Emission Survey Questionnaires, (2) site visits, (3) meetings with stakeholders, and (4) literature.

As required under section 112(d) of the Act, the EPA developed the MACT floor based on "* * * the average limitation achieved by the best performing 12 percent of the existing sources * * *." The EPA obtained information on 200 glycol dehydration units that were considered to be major sources of HAP (prior to control). Of these, 34 percent (67 units) were controlled using a variety of control technologies, including condensation, combustion, and a combination of condensation and combustion. The types of control technologies used by the industry have been demonstrated, in other applications, to achieve varying levels of emission reduction (ranging from 95.0 to 98 percent or better). The EPA could not identify a technical basis for the variation in the performance levels achieved by the controls reported to be used to control process vents on glycol dehydration units. In order to account for the variability in HAP emission reduction efficiencies, the EPA selected 95.0 percent as the required emission reduction (i.e., the MACT floor) for large glycol dehydration units in the oil and natural gas production source category.

The final standards require that all process vents on new and existing glycol dehydration units that are located at major HAP sources be controlled unless (1) the actual flowrate of natural gas to the glycol dehydration unit is less than 85 thousand m^3/day, on an annual average basis; or (2) the actual average benzene emissions from the glycol dehydration unit are less than 0.90 Mg/yr. Glycol dehydration units that meet these criteria are not subject to the control requirements of subpart HH.

Glycol dehydration units that are subject to the control requirements are required to connect, through a closed-vent system, each process vent on the glycol dehydration unit to an air

emission control system. The control system must reduce emissions: (1) by 95.0 percent or more of HAP, (2) to an outlet concentration of 20 parts per million by volume (ppmv) or less (for combustion devices), or (3) to a benzene emission level of 0.90 Mg/yr or less. Pollution prevention measures, such as process modifications or combinations of process modifications and one or more control devices that reduce the amount of HAP emissions generated, are allowed as an alternative provided they achieve the required emission reductions.

3. Storage Vessel Standards

Final standards are established for existing and new storage vessels with the potential for flash emissions that are located at major HAP sources. Storage vessels with the potential for flash emissions are defined as those that contain a hydrocarbon liquid with a storage tank GOR equal to or greater than 0.31 m^3/liter, an API gravity equal to or greater than 40 degrees, and an actual annual average throughput of hydrocarbon liquids equal to or greater than 79,500 liter/day.

Flash emissions from storage vessels occur when a hydrocarbon liquid with a high vapor pressure flows from a pressurized vessel into a vessel with a lower pressure. Flash emissions typically occur when a hydrocarbon liquid, such as condensate, is transferred from a production separator to a storage vessel. The final standards require that storage vessels with the potential for flash emissions be equipped with an air emission control system.

Under the final standards, a storage vessel with the potential for flash emissions is required to be equipped with a cover vented through a closed-vent system to a control device that (1) recovers or destroys HAP emissions with an efficiency of 95.0 percent or greater, or (2) for combustion devices, reduces HAP emissions to an outlet concentration of 20 ppmv or less.

A pressurized storage vessel that is designed to operate as a closed system is considered in compliance with the promulgated requirements for storage vessels. In addition, owners or operators that are meeting the requirements of 40 CFR part 60, subpart Kb; 40 CFR part 63, subpart G; or 40 CFR part 63, subpart CC, are also considered in compliance.

4. Standards for Equipment Leaks

The final rule requires owners and operators of natural gas processing plants that are major HAP sources to control HAP emissions from leaks from ancillary equipment and compressors that contain or contact a liquid or gas that has a total volatile hazardous air pollutant (VHAP) concentration equal to or greater than 10 percent by weight. The final equipment leak standards do not apply to ancillary equipment and compressors that operate in VHAP service less than 300 hours per year. Also, an owner or operator that is subject to and controlled under the provisions of 40 CFR part 60, subpart KKK; or 40 CFR part 61, subpart V; or 40 CFR part 63, subpart H, is only required to comply with the requirements of that subpart.

For equipment subject to these standards at either an existing or new source, the owner or operator is required to implement a LDAR program and where necessary, perform equipment modifications. Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located (1) at a nonfractionating facility that processes less than 283 thousand m^3/day, or (2) on the Alaskan North Slope, are exempt from some of the routine LDAR monitoring requirements. In addition, reciprocating compressors in wet gas service are exempt from the compressor requirements.

5. Air Emission Control Equipment Requirements

Specific performance and operating requirements are included for each control device installed by the owner or operator. Control devices are required to reduce the mass content of the gases vented to the device (1) by 95.0 percent or greater by weight as total organic compounds (TOC), less methane and ethane, or total HAP; or (2) for combustion devices, to an outlet HAP or TOC concentration of 20 ppmv or less.

Closed vent systems that contain bypass devices that could divert vent streams away from the control device must either install a flow indicator or secure the bypass valve in the nondiverting position to ensure that the control device is not bypassed.

Certain specifications for covers apply based on the type of cover and where the cover is installed. Requirements are specified for vapor leak-tight covers installed on storage vessels.

6. Test Methods and Procedures

An owner or operator must be able to demonstrate that the criteria for exemptions from control requirements are met when controls are not applied or when existing controls are adequate to meet the exemption criteria. For example, owners or operators of glycol dehydration units that do not install air emission controls because the actual average benzene emission rate from the unit is less than 0.90 Mg/yr must be able to demonstrate that the actual average benzene emission rate from the unit is less than 0.90 Mg/yr.

Procedures for demonstrating the HAP emission reduction efficiency of control devices and HAP concentration are consistent with procedures established in previously promulgated NESHAP that apply to emission sources similar to those addressed in the final standards. Engineering calculations, modeling (using EPA-approved models), and previous test results are generally acceptable means of demonstrating compliance, except where such means are not conclusive. Test procedures are specified in the final rule for use when testing is required to demonstrate compliance.

An alternative test procedure is provided to demonstrate control efficiency when a condenser is used for controlling emissions from a glycol dehydration unit reboiler vent. The inclusion of the alternative test procedure is appropriate in this standard because of difficulties associated with testing the inlet to a condenser in this application.

Procedures and test methods are also specified for the detection of leaks from ancillary equipment and compressors and leaks in covers and closed vent systems.

7. Monitoring and Inspection Requirements

The final standards require that the owner or operator periodically inspect and monitor air emission control equipment. Periodic inspections are required for certain types of covers to ensure gaskets and seals are in good condition and for closed-vent systems to ensure all fittings remain leak-tight. An owner or operator is required to periodically perform these inspections to determine and ensure that these equipment operate with no leaks.

For covers, the owner or operator is required to perform initial and semiannual visual inspections. For closed vent systems, the owner or operator is required to perform an initial leak inspection and annual visual inspections to detect leaks. In addition, the owner or operator of closed vent system components that are not permanently or semi-permanently sealed must perform annual leak inspections.

The final standards require continuous monitoring of control device operation through the use of automated instrumentation. Continuous monitoring systems measure and record control

device operating parameters to ensure compliance with the standards.

8. Recordkeeping and Reporting Requirements

The recordkeeping and reporting requirements associated with the final standards are primarily those specified in the part 63 General Provisions (40 CFR 63, subpart A). Major sources are subject to all of the requirements of the General Provisions with the exception that (1) owners or operators are allowed up to 1 year from the effective date of the standards to submit the initial notification described in § 63.9(b) of subpart A; and (2) owners or operators are allowed to submit Periodic reports and startup, shutdown, and malfunction reports semiannually instead of quarterly. The EPA selected these specific exceptions due to the large number of facilities that need to submit notifications or reports related to the NESHAP. The EPA believes that these exceptions will not adversely affect the implementation of the final regulation or reduce its impact on HAP emissions.

B. Promulgated Standards for Natural Gas Transmission and Storage for Major Sources

The final standards amend title 40, chapter I, part 63 CFR by adding a new Subpart HHH—National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities. The standards apply to owners and operators of facilities that process, upgrade, transport or store natural gas prior to delivery to a local distribution company (LDC) or a final end user if no LDC is present. A compressor station that transports natural gas to a natural gas processing plant is considered a part of the oil and natural gas production source category.

A facility's potential to emit is required to be calculated based on a maximum facility throughput. For storage facilities or facilities that store and transport natural gas, the final rule specifies procedures for calculating this maximum throughput based on the facility's maximum withdrawal and injection rates and the working gas capacity of the storage field. Facilities that only transport natural gas are required to calculate maximum throughput as the highest annual throughput over 5 years prior to the effective date of the rule, multiplied by 1.2. The owner or operator must also establish maximum values of other parameters required to calculate emissions over the same period used to determine maximum throughput.

1. Applicability

The final standards for natural gas transmission and storage facilities require that the owner or operator of a major source of HAP reduce HAP emissions from glycol dehydration units through the application of air emission control equipment or pollution prevention measures, or a combination of both. The owner or operator of a facility that processes less than 28.3 thousand m^3/day of natural gas facilitywide on an actual annual average basis, where glycol dehydration units are the only HAP emission points, is exempt from the requirements of subpart HHH.

2. Glycol Dehydration Unit Process Vent Standards

The MACT standard for process vents on new and existing glycol dehydration units was set at the floor level of control. To determine the MACT floor, the EPA divided glycol dehydration units into two sizes: (1) small glycol dehydration units with actual annual average natural gas throughputs less than 283 thousand m^3/day or with actual average benzene emissions less than 0.90 Mg/yr, and (2) large glycol dehydration units with actual annual average natural gas throughputs equal to or greater than 283 thousand m^3/day or with actual average benzene emissions equal to or greater than 0.90 Mg/yr. As discussed in the January 15, 1999 supplemental notice (64 FR 2611), the EPA determined that the MACT floor for large glycol dehydration units was 95.0 percent control. For small glycol dehydration units, the EPA determined that the MACT floor was no control and that it was not cost effective to select a regulatory alternative beyond the floor.

The final standards require that all process vents on new and existing glycol dehydration units that are located at major HAP sources be controlled unless (1) the actual annual average flowrate of natural gas to the glycol dehydration unit is less than 283 thousand m^3/day, or (2) the actual average benzene emissions from the glycol dehydration unit are less than 0.90 Mg/yr.

Glycol dehydration units that are subject to the control requirements are required to connect, through a closed-vent system, each process vent on the glycol dehydration unit to an air emission control system that reduces emissions: (1) by 95.0 percent or more of HAP, (2) to an outlet HAP concentration of 20 ppmv or less, for combustion devices, or (3) to a benzene emission level of 0.90 Mg/yr or less. As with the final standards for the oil and natural gas production NESHAP, pollution prevention measures, such as process modifications (or combinations of process modifications and control devices) that reduce the amount of HAP emissions generated, are allowed as an alternative provided they achieve the required emission reductions.

3. Air Emission Control Equipment Requirements

Specific performance and operating requirements are included for each control device installed by the owner or operator. Control devices are required to reduce the mass content of the gases vented to the device (1) by 95.0 percent or greater by weight as TOC, less methane and ethane, or total HAP; or (2) for combustion devices, to an outlet HAP or TOC concentration of 20 ppmv or less.

Closed vent systems that contain bypass devices that could divert vent streams away from the control device must either install a flow indicator or secure the bypass valve in the nondiverting position to ensure that the control device is not bypassed.

4. Test Methods and Procedures

An owner or operator must be able to demonstrate that the criteria for exemptions from control requirements are met when controls are not applied or when existing controls are adequate to meet the exemption criteria. For example, owners or operators of glycol dehydration units that do not install air emission controls because the actual average benzene emission rate from the unit is less than 0.90 Mg/yr must be able to demonstrate that the actual average benzene emission rate from the unit is less than 0.90 Mg/yr.

Procedures for demonstrating the HAP emission reduction efficiency of control devices and HAP concentration are consistent with procedures established in previously promulgated NESHAP that apply to emission sources similar to those addressed in the final standards. Engineering calculations, modeling (using EPA-approved models), and previous test results are generally acceptable means of demonstrating compliance, except where such means are not conclusive. Test procedures are specified in the final rule for use when testing is required to demonstrate compliance.

An alternative test procedure is provided to demonstrate control efficiency when a condenser is used for controlling emissions from a glycol dehydration unit reboiler vent. The inclusion of the alternative test procedure is appropriate in this standard because of difficulties

associated with testing the inlet to a condenser in this application. Procedures and test methods are also specified for detection of leaks in closed-vent systems.

5. Monitoring and Inspection Requirements

The monitoring and inspection requirements are (1) periodic control equipment monitoring, (2) initial leak detection inspections for closed-vent systems to ensure all fittings are leak-tight, (3) annual visual inspections of closed-vent systems (closed vent system components that are not permanently or semi-permanently sealed are also required to be annually inspected for leaks), and (4) continuous monitoring of control device operation. Continuous monitoring requires the use of automated instrumentation that measures and records control device compliance operating parameters.

C. Recordkeeping and Reporting Provisions

The recordkeeping and reporting requirements associated with the final standards are primarily those specified in the part 63 General Provisions (40 CFR 63, subpart A). Major sources are subject to all of the requirements of the General Provisions, except that (1) owners or operators are allowed up to 1 year from the effective date of the standards to submit the initial notification required under § 63.9(b) of subpart A and (2) owners or operators are allowed to submit Periodic reports and startup, shutdown, and malfunction reports semiannually instead of quarterly. These exceptions were selected to maintain consistency between the major source provisions of the final regulations for natural gas transmission and storage facilities and oil and natural gas production facilities.

IV. Summary of Impacts

A. HAP Emission Reductions

For major sources, the EPA estimated that the final oil and natural gas production standards for existing sources will result in a reduction of HAP emissions from 39,000 Mg/yr to 9,000 Mg/yr. In addition, HAP emissions would be reduced by 3,000 Mg/yr for new sources over the first 3 years after promulgation of these standards.

Table 1 presents the major source emission reductions, in addition to other environmental, energy, and cost impacts, that the EPA estimates will occur from the implementation of the standards for oil and natural gas production.

TABLE 1.—SUMMARY OF ESTIMATED ENVIRONMENTAL, ENERGY, AND ECONOMIC IMPACTS EXISTING AND NEW MAJOR SOURCES

Impact category	Existing oil and natural gas production	New oil and natural gas production	Existing natural gas transmission and storage *
Estimated number of impacted facilities	440	44	7
Emission reductions (Mg/yr):			
HAP	30,000	3,000	390
VOC	61,000	6,100	610
Methane	7,000	700	230
Secondary environmental emission increases (Mg/yr):			
Sulfur oxides	<1	<1	<1
Nitrogen oxides	<5	<1	<1
Carbon monoxide	<1	<1	<1
Energy (Kilowatt hours per year)	38,000	3,800	None
Implementation costs (Million of July 1993 $):			
Total installed capital	6.5	0.7	0.28
Total annual	4.0	0.4	0.3

*No new major sources are anticipated for this source category after the effective date for new sources and in the first 3 years following promulgation of the rule.

The EPA estimates that the final natural gas transmission and storage standards for existing sources will result in a reduction of HAP emissions from 2,100 Mg/yr to 1,710 Mg/yr. No new major sources are anticipated in the first 3 years after promulgation of this NESHAP. Table 1 also presents the major source emission reductions, in addition to other environmental, energy, and cost impacts, that the EPA estimates will occur from the implementation of the standards for existing natural gas transmission and storage facilities.

The air emission reductions achieved by these standards, when combined with the air emission reductions achieved by other standards mandated by the Act, will accomplish the primary goal of the Act to:

* * * enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population.

B. Secondary Environmental Impacts

Other environmental impacts are those associated with operation of certain air emission control devices. The EPA's secondary air emissions impact analyses for the oil and natural gas production source category consider a facility's ability to handle collected vapors. Some remotely located facilities may not be able to use collected vapor for fuel or recycle it back into the process. In addition, it may not be technically feasible for some facilities to safely utilize the non-condensable vapor streams from condenser systems as an alternative fuel source. An option for these facilities is to combust these vapors by flaring, rather than installing condensers.

These limitations are reflected in the analyses conducted by the EPA. In the analyses, the EPA estimated that (1) 45 percent of all impacted production facilities will be able to use collected vapors from installed control options as an alternative fuel source for an on-site combustion device such as a process heater or the glycol dehydration unit firebox, (2) 45 percent will be able to recycle collected vapors from installed control options into a low pressure header system for combination with other hydrocarbon streams handled at the facility, and (3) 10 percent will direct all collected vapor to an on-site flare. The secondary air impacts are associated with flare operations.

The adverse secondary air impacts would be minimal in comparison to the primary HAP reduction benefits from the implementation of the control options for major oil and natural gas sources. The estimated national annual increase in secondary air pollutant emissions that would result from the use of a flare to comply with the standards is estimated to be less than 1.0 Mg/yr for both sulfur oxide (SO_x) and carbon monoxide (CO) and less than 5 Mg/yr for nitrogen oxides (NO_x). These estimates are for major oil and natural gas production sources.

The anticipated increases in secondary air pollutant emissions are based on six affected facilities utilizing flares and are estimated to be less than 1.0 Mg/yr for SO_x, CO, and NO_x, each, from the implementation of the control options for major sources at natural gas transmission and storage facilities.

The adverse water impacts anticipated from the implementation of control options for the standards are expected to be minimal. The water impacts associated with the installation of a condenser system for the glycol dehydration unit reboiler vent would be minimal. This is because the condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal by reinjection.

Similarly, the water impacts associated with installation of a vapor control system would be minimal. This is because the water vapor collected along with hydrocarbon vapors in the vapor collection and redirect system can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with the produced water for disposal by reinjection.

There are no adverse solid waste impacts anticipated from the implementation of the standards.

C. Energy Impacts

Energy impacts are those energy requirements associated with the operation of emission control devices. The EPA estimated that the operation of add-on control devices (e.g., condensers, flares, etc.) would not require additional energy. Vapor collection and redirect systems used for the control of emissions from a fixed-roof storage vessel require electricity for operation of the primary components of the system, including fans and blowers.

The EPA estimated that the annual energy requirements for each vapor collection/recovery system installed to comply with the oil and natural gas production storage vessel standards are estimated to be 300 kilowatt hours per year (kW-hr/yr). The EPA also estimated that approximately 125 oil and natural gas production major source facilities would install this control option. The national energy demand increase for existing sources was estimated to be 38,000 kW-hr/yr.

Because storage vessels are not regulated under the natural gas transmission and storage NESHAP, the EPA estimated that there would be no national energy demand increase from the operation of any of the control options analyzed under the natural gas transmission and storage standards for major sources.

The standards encourage the use of emission controls that recover hydrocarbon products, such as methane and condensate, that can be used on-site as fuel or reprocessed, within the production process, for sale. Thus, the standards have a positive impact associated with the recovery of non-renewable energy resources.

D. Cost Impacts

The estimated total capital cost to comply with the rule for existing major sources in the oil and natural gas production source category is approximately $6.5 million. The total capital cost for new major sources is estimated to be approximately $700,000.

The total estimated net annual cost to industry to comply with the requirements for existing major sources in the oil and natural gas production source category is approximately $4.0 million per year. The total net annual cost for new major sources is approximately $400,000 per year. These estimated annual costs include (1) the cost of capital; (2) operating and maintenance costs; (3) the cost of monitoring, recordkeeping, and reporting (MRR); and (4) any associated product recovery credits.

The estimated total capital cost to comply with the rule for major sources in the natural gas transmission and storage source category is approximately $280,000.

The total estimated net annual cost to industry to comply with the requirements for major sources in the natural gas transmission and storage source category is approximately $300,000. As with the oil and natural gas production total estimated annual cost to industry, this annual cost estimate includes (1) the cost of capital, (2) operating and maintenance costs, (3) the cost of MRR, and (4) any associated product recovery credits.

E. Economic Impacts

The EPA prepared an economic impact analysis that evaluates the impacts of the regulation on affected producers, consumers, and society. The economic analysis focuses on the regulatory effects on the U.S. natural gas market that is modeled as a national, perfectly competitive market for a homogenous commodity. The analysis does not include a model to assess the regulatory effects on the world crude oil market because the regulation is anticipated to affect less than 5 percent of the total U.S. crude oil production, and thus, it is unlikely to have any influence on the U.S. supply of crude oil or world crude oil prices.

The imposition of regulatory costs on the natural gas market result in negligible changes in natural gas prices, output, employment, foreign trade, and business profitability. Price and output changes as a result of the regulation are less than 0.0005 of 1 percent, which is significantly less than observed market trends. For example, between 1992 and 1993 the average change in wellhead price increased by 14 percent, while domestic production rose by 3 percent.

The total annual social cost of the regulation is $4.6 million, which accounts for the compliance cost imposed on producers, as well as market adjustments that influence the revenues to producers and consumption by end users, plus the associated deadweight loss to society of the reallocation of resources.

V. Significant Comments and Changes to the Proposed Standards

In response to comments received on the proposed standards, several changes have been made to the final rules. While several of these changes are clarifications designed to clarify the Agency's original intent, a number of them are significant changes to the proposed standard requirements. A summary of the substantive comments and/or changes made since proposal are described in the following sections. Detailed Agency responses to public comments and the revised analysis for the final rule are contained in the BID, volume 2 (EPA-453/R-99-004b, May 1999) and docket (see **ADDRESSES** section of this preamble).

A. Definition of Facility

The EPA developed the proposed definition of facility to (1) identify criteria that define a grouping of emission points that meet the intent of the language contained in section 112(a)(1) of the Act: "* * * located within a contiguous area and under

common control, * * *"; and (2) contain terms that are meaningful and easily understood within the regulated industries. The proposed definition was based on individual surface sites and the idea that equipment located on different oil and gas properties (oil and gas lease, mineral fee tract, subsurface unit area, surface fee tract, or surface lease tract) shall not be aggregated. In addition, the proposed definition of a production field facility was limited to glycol dehydration units and storage vessels with the potential for flash emissions. The EPA requested comments on the proposed definition of facility. Specifically, the EPA requested comments on whether the proposed definition appropriately implements the intent of the major source definition in section 112(a)(1) for the oil and natural gas production and natural gas transmission and storage source categories or whether another definition would better implement this intent.

Several commenters responded to the EPA's request for comments on the definition of facility. The commenters requested clarification of, or suggested changes to, the proposed definition of facility. The commenters were primarily concerned that large groupings of equipment would inappropriately be considered a part of the same facility, resulting in a major source determination. In particular, the commenters were concerned about how subparts HH and HHH would treat units, contiguous surface sites, and surface sites with equipment under separate ownership. The commenters requested clarification of the definition of facility to prevent this confusion.

The EPA intended that the facility definition, as it applies to the oil and natural gas production source category, should lead to an aggregation of emissions in a major source determination that is reasonable, consistent with the intent of the Act, and easily implementable.

The EPA believes that it would not be reasonable to aggregate emissions from surface sites that are located on the same lease, but are great distances apart. The definition of facility states that equipment located on different oil and natural gas properties (e.g., leases) are not to be aggregated. Although units (which are made up of more than lease or tract) are under common control, under the definition of facility, the equipment located on different leases contained within each unit would not be aggregated.

Under section 112(a)(1) of the Act, a major source is defined as "* * * any stationary source or group of stationary sources located within a contiguous area and under common control.* * *" The EPA believes that by defining facility based on individual surface sites, the EPA has provided relief for individual surface sites that are located on the same lease, but are far apart, and excluding contiguous surface sites located on the same lease would be contrary to the intent of the Act.

Finally, the terms contained in the definition of facility (e.g., surface site and lease) are well understood within the industry and by enforcement agencies, and the EPA does not believe that additional definitions or clarifications regarding these terms are necessary.

In response to comments regarding specific clarification to the definition of facility, the EPA has made several changes to the definition of facility. The EPA modified the definition of facility to point to the definition of "surface site." In subpart HHH, the EPA has added a definition of "surface site," and modified the definition of facility to point to the new definition of "surface site."

The EPA further modified the definition of facility in subpart HH by: (1) specifying that "upgraded" means "the removal of impurities or other constituents to meet contract specifications"; (2) changing the term "unit areas" to "surface unit areas"; and (3) specifying that separate surface sites, whether or not connected by a road, waterway, power line or pipeline, would not be considered a part of the same facility.

Commenters recommended that the EPA expand its definition of production field facility in subpart HH to include additional HAP emission points beyond glycol dehydration units and storage vessels with flash emission potential. The concern was that several facilities that could otherwise be major sources of HAP would be exempt from subpart HH under the proposed definition of facility.

One of the EPA's objectives was to develop a definition of facility that would comply with section 112(n)(4) of the Act and at the same time, reduce the burden on owners and operators in making a major source determination. The EPA's evaluation of HAP emission sources in production field operations suggested that other potential HAP emission points at these facilities (e.g., equipment leaks) would be inconsequential to the determination of a facility's major source status. The EPA believes that eliminating the need to quantify HAP emissions from small sources at production field facilities would not affect the major source status determination, but would reduce the burden on owners or operators.

Other commenters requested that the EPA clarify, within the definition of facility in subpart HHH, whether the EPA intended to exclude facilities used to store natural gas after the gas enters the local distribution system of a gas utility. The commenter recommended that the EPA clarify that the definition of facility applies all the way to the end user only if there is no local distribution company.

The affected source in the natural gas transmission and storage source category should run all the way to the end user only if there is no local distribution company. Therefore, the EPA modified the definition of facility in subpart HHH to state that if there is not a local distribution company, the facility runs to the end user.

Some commenters were concerned that the definition of facility in subpart HH suggests that a natural gas storage facility could qualify as a production facility, since natural gas storage takes place in depleted gas wells, and liquids are transferred for processing to the plant.

Subpart HH contains a definition of field natural gas which means "* * * natural gas that is extracted from a production well prior to entering the first stage of processing, such as dehydration." In addition, a production well is defined in § 63.761 as a "* * * hole drilled in the earth from which * * * field natural gas is extracted." Since the gas handled by a natural gas storage facility has been dehydrated, the EPA believes that the natural gas handled by a storage facility would not be considered field natural gas. Therefore, given the definitions of production well and field natural gas, a natural gas storage field that uses a depleted gas well for storage would not qualify as a production facility. The EPA does not believe that clarification of the definition of facility is necessary in response to this comment.

B. Definition of "Associated Equipment"

Section 112(n)(4)(A) of the Act states:

> * * * emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section.

According to the statutory definition of major source in section 112(a)(1) of the Act, HAP emissions from all emission points within a contiguous area and under common control must be counted in a major source determination. By stating that emissions from any oil and gas production and exploration well (with its associated equipment) cannot be aggregated for a major source determination, the provisions of section 112(n)(4)(A) mean HAP emissions from each well and each piece of equipment considered to be associated with the well must be evaluated separately in a major source determination. That is, any well or piece of associated equipment would only be determined to be a major source if HAP emissions from that well or piece of associated equipment were major.

Therefore, to implement this special provision of the Act for the oil and natural gas production source category, a definition of "associated equipment" was necessary. However, a definition for the term "associated equipment" was not provided in the statute. The EPA proposed that "associated equipment" be defined as all equipment associated with a production well up to the point of custody transfer, except that glycol dehydration units and storage vessels with the potential for flash emissions would not be associated equipment. In developing this proposed definition, the Agency identified and evaluated several options. The Agency also sought and received input from industry and other stakeholders.

In the proposal, the EPA specifically requested comments on the proposed definition of "associated equipment." The EPA requested that commenters disagreeing with the proposal provide alternative definition options, along with supporting documentation, that would provide the relief that Congress intended for this industry in section 112(n)(4), while preserving the EPA's ability to regulate HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions.

Several commenters responded to the EPA's request for comments on the EPA's interpretation of the term "associated equipment" as used in section 112(n)(4) of the Act. Although several commenters did not fully support the EPA's interpretation of section 112(n)(4), they acknowledged that the proposed definition of associated equipment is a workable solution in comparison to other options for this definition. According to the commenters, aggregation of glycol dehydration units and storage vessels with flash emission potential would result in the same major source determination as aggregation of all potential sources, but would reduce the burden on the facility operator. Other commenters argued that section 112(n)(4) mandates no aggregation of emissions from individual sources at oil and gas production fields, and that the EPA exceeded its statutory authority by allowing for the aggregation of emissions from glycol dehydration units and storage vessels with the potential for flash emissions.

After consideration of these comments, the EPA agrees with those commenters who supported the proposed definition as a workable solution, and is promulgating the definition as proposed. The EPA disagrees with those commenters who argued that the Agency exceeded its statutory authority for the reasons discussed below.

Section 112(a)(1) generally requires HAP emission points within a contiguous area and under common control to be aggregated in a major source determination for the purposes of section 112. While this approach is appropriate for facilities in most industries, it may lead to unreasonable aggregations if strictly applied to oil and natural gas field operations. Given that some oil and natural gas operations (e.g., a production field) may cover several square miles or that leases and mineral rights agreements give some companies control over a large area of contiguous property, determination of major source status strictly by the language of section 112(a)(1) could mean in this industry that HAP emissions must be aggregated from emission points separated by large distances.

Congress addressed the unique aspects of the oil and natural gas production industry by providing the special provisions in section 112(n)(4) of the Act referring to the "* * * oil and gas exploration and production well (and its associated equipment) * * *." However, Congress did not provide a definition of the term "associated equipment" in the statutory language, leaving its interpretation to the EPA. A definition of this term is important in determining the major source status of facilities in both the oil and natural gas production and the natural gas transmission and storage source categories.

In the absence of clear guidance in the statute, the EPA evaluated various options for defining "associated equipment" prior to proposal. The EPA's objective was to arrive at a reasonable interpretation that would (1) provide substantive meaning to the term "associated equipment" consistent with congressional intent; (2) prevent the aggregation of small, scattered HAP emission points in major source determinations; (3) be easily implementable; and (4) not preclude the aggregation of significant HAP emission points in the source category. Due to the lack of clarity in the statute and the potential impact on major source determinations, the Agency worked with industry stakeholders to identify and evaluate options prior to proposal. Industry representatives expressed their goals for the interpretation of associated equipment, and provided information on the magnitude of HAP emission points and the potential impacts of various options considered by the EPA.

The EPA considered, but rejected, a definition based on a narrow interpretation that would include only valves and fittings on a well as being associated equipment primarily because this option would not provide any additional relief to industry beyond what would have been provided had Congress only used the term "well" in section 112(n)(4) of the Act. The EPA also rejected a definition, initially recommended by industry, that was based on a broad interpretation that would include equipment far beyond the well as associated equipment.

In discussions with industry stakeholders over an extended period of time prior to proposal, the Agency sought to reach a workable solution on the definition of associated equipment, one that recognized the need to implement relief for this industry as Congress intended, and that also allowed for the appropriate regulation of significant emission points. In a technical evaluation, the EPA identified glycol dehydration units and storage tanks with flash emission potential as substantial contributors to HAP emissions, particularly relative to sources such as production wells. This conclusion was supported by industry. Under the proposed approach, associated equipment was defined as all equipment up to the point of custody transfer, excluding glycol dehydration units and storage vessels with the potential for flash emissions. This approach also included a definition of facility in the rule that effectively limited the distance over which all emission points (including glycol dehydration units and storage vessels with the potential for flash emissions) may be aggregated. Based on discussions with industry prior to proposal, as well as comments received supporting the proposed definition of associated equipment, the Agency believes that the proposed approach

best meets both industry and EPA goals for implementation of the language of section 112(n)(4).

Commenters who argued that the Agency exceeded its authority with the definition of associated equipment offered no substantive new information to support their claim. The EPA could not find support in the statute or in the legislative history that indicated that Congress intended to preclude aggregation of all emission points, including such significant ones as glycol dehydration units and storage tanks with flash emission potential through their inclusion as associated equipment. Rather, there are clear indications, in the EPA's judgement, that Congress' primary intent was to preclude the aggregation of small emitting sources over vast distances. The legislative history of the Act, for example, indicates that Congress believed that oil and natural gas production wells and their "associated equipment" generally have low HAP emissions, and are typically located in widely dispersed geographic areas, rather than being concentrated in a single area. The EPA used this background as a guide in developing an interpretation of "associated equipment" along with available data on HAP emissions from emission points within the oil and natural gas production source category. The EPA believes that glycol dehydration units and storage vessels with the potential for flash emissions are not the type of small HAP emission points that Congress intended to be included in the definition of associated equipment.

After the EPA's review and consideration of all comments received on the proposal, the definition of associated equipment promulgated in today's rule is the same as proposed.

C. Applicability

1. Black Oil Definition

In the proposed subpart HH, the EPA provided an exemption from the subpart for facilities that exclusively handle black oil. Black oil was defined in subpart HH as a hydrocarbon liquid with an API gravity less than 40 degrees and a GOR less than 0.31 m^3/liter of liquid.

Several commenters questioned the EPA's basis for the black oil definition. The commenters requested that the EPA revise the GOR and API gravity cutoffs. One commenter stated that it was unclear whether the definition of black oil, with the proposed cutoffs, was a determination related to human health risk.

During the development of the proposal, representatives of the oil and natural gas production industry stressed that their industry was composed of large numbers of facilities that handle black oil, and that black oil was not a significant contributor to overall source category HAP emissions. The EPA reviewed the available information and agreed with the industry representatives that facilities that exclusively handle black oil are not significant contributors to overall HAP emissions from the source category. Furthermore, the EPA did not identify control technologies, designed to reduce HAP, in use at existing facilities that exclusively process, handle, or store black oil. Therefore, the EPA determined that the MACT floor for black oil facilities was no control. This determination was not made based on the health risks associated with black oil.

The EPA developed the proposed definition of black oil based on a series of technical articles that describe five basic hydrocarbon fluids that typically exist in a reservoir: black oil, volatile oil, retrograde gas, wet gas, and dry gas (Air Docket A-94-04). Of these, black oil and volatile oil exist as liquid in the reservoir. Black oil, which is a mixture of chemical species ranging from methane to large, heavy, nonvolatile organic molecules, is in solution with dry gas, which is primarily methane. Volatile oil, which contains fewer heavy molecules, is in solution with retrograde gas, which has fewer of the heavy organic molecules.

According to these articles, reservoir fluid types are determined by rules-of-thumb based on an initial producing GOR, stock-tank liquid gravity, and stock tank liquid color. In particular, fluid type is usually determined by initial producing GOR and confirmed by stock tank gravity values and stock tank color. (Note: The distinction between initial producing GOR and producing GOR is important. As reservoir pressure reduces over time, the producing GOR for black oil increases. Therefore, if any other GOR is used, the facility may not appear to qualify for the exemption.) The rule-of-thumb for volatile oil is an initial producing GOR of 0.31 m^3/liter. Volatile oil is also suspected if the API gravity is equal to or greater than 40 degrees and a color that is brown, reddish, orange, or green. The rule-of-thumb for black oil is an initial producing GOR less than 0.31 m^3/liter, an API gravity of less than 45 degrees, and a color that is dark, usually black (sometimes with a greenish cast) or brown.

Since color determination is subjective, the EPA selected initial producing GOR and API gravity as quantifiable criteria for defining black oil. In addition, since there is a gap between the rule-of-thumb API gravity criteria for black oil and volatile oil, the EPA selected the lower, more conservative value of 40 degrees. The EPA believes that using a higher API gravity to define black oil, such as 45 or 50 degrees as recommended by the commenters, would increase the possibility that the liquid is a volatile oil, thus exempting sources that are likely to have higher HAP emissions. The EPA believes that the criteria for defining a black oil, which were obtained directly from widely recognized definitions of black oil and volatile oil used in the oil and natural gas industry, are technically sound for identifying which sources are included as black oil facilities. Therefore, the EPA has not modified the black oil definition.

2. Potential-to-Emit

Several commenters were concerned with the methods used to determine whether or not a facility was a major source. In particular, the EPA received several comment letters regarding the calculation of a facility's potential-to-emit (PTE) when determining a facility's major source status. The EPA received comments regarding the calculation of PTE on the following issues: (1) potential emissions calculated to determine major source status should consider controls and operational limitations whether or not they are federally enforceable as specified in the *National Mining Congress* v. *EPA* (59 F.3d.1351, D.C. Cir. 1995) court case; (2) potential emissions should not be based on equipment operating capacity because it would result in overregulation, but should consider the inherent operating limitations of the facility (e.g., declining production levels over time); (3) the EPA should provide a simplified approach to calculate PTE, which takes into account design and operational limitations; and (4) the EPA should use the logic in the PTE Transition policy where sources with low emissions may be considered nonmajor if records of actual emissions are maintained.

a. *Use of Limitations in Calculating PTE.* The EPA received comments requesting that potential emissions calculated to determine major source status should consider controls and operational limits whether or not they are federally enforceable.

The EPA believes that by referring to the definition of PTE in § 63.2 of subpart A, subparts HH and HHH contain the provisions for accounting for control

devices and federally enforceable operating limitations as requested by the commenters.

With respect to the *National Mining* court case, the court required the EPA to reconsider the Federal enforceability requirement, but did not vacate the requirement. As a result, the requirement for Federal enforceability is still in effect. The definition of PTE for the NESHAP program (40 CFR 63.2) is currently under review, and the EPA is engaged in a rulemaking process to amend the requirements in the General Provisions. The EPA has not modified subparts HH and HHH in response to these comments.

b. *Use of Inherent Design and Operational Limitations in Calculating PTE.* Several commenters were concerned that PTE estimates, as defined in the General Provisions, would be unrealistically high and would subject many small insignificant sources to the NESHAP requirements. The commenters requested that PTE be based on the inherent design and operational limitations of production and transmission and storage facilities, such as throughput rates.

According to commenters, the throughput of oil and natural gas production operations declines over time, and existing equipment is often designed, constructed and operated based on high initial production rates. Therefore, the commenters suggested that the facilities are usually operated at actual throughput rates that are much lower than the design capacities.

The EPA agrees that there are certain inherent throughput limitations associated with the production of oil and natural gas, primarily related to declining production rates. Therefore, the final subpart HH specifies a method for calculating maximum facility throughput to determine major source status and applicability to subpart HH. This method is based on a facility's past production rate and ability to document declining annual operations. However, it is the responsibility of the owner or operator to be aware of changes that could require a facility to recalculate its PTE and to do so in a timely manner. The owner or operator could be found in violation back until the point in time at which an engineering judgement would have shown that the facility was reasonably capable of emitting at major source thresholds. A detailed discussion is presented in section 2.1.1 of the BID volume 2.

The EPA also received comments that the EPA should consider the seasonal operation of natural gas storage facilities in estimating potential emissions, and that the facility's PTE cannot be based on withdrawal for the entire season at maximum capacity. The commenters explained that natural gas storage facilities must spend part of the year injecting gas, and that withdrawal rates decrease as the storage field's pressure drops.

The EPA agrees that natural gas storage facilities have inherent limitations due to the nature of their operations. Therefore, the final rule (subpart HHH) contains a method for calculating maximum facility throughput to determine major source status and applicability of subpart HHH. The method is based on the maximum withdrawal and injection rates and the working gas capacity for a given storage field. A more detailed discussion is presented in section 2.1.1 of BID volume 2.

c. *Simplified Approach to Calculate PTE.* Several commenters recommended a simplified approach to calculating PTE, such as screening equations similar to those developed for other NESHAP, to take into account design and operational limitations.

The EPA evaluated the use of an equation similar in structure to the Gasoline Distribution NESHAP, 40 CFR part 63, subpart R. After extended effort, the EPA found that the number of variables was too extensive to allow development of a manageable equation. The EPA also received supplemental comments from industry and trade associations indicating that their efforts in developing such an equation resulted in the same outcome (Air Docket A-94-04).

Therefore, as an alternative, the EPA developed a simplified major source determination (MSD) for HAP emission sources in the oil and natural gas production and natural gas transmission and storage source categories. The simplified MSD allows the owner or operator of a facility to easily determine (1) if they are major sources and whether NESHAP requirements apply to their facility, and (2) if they are required to obtain a title V operating permit.

Therefore, the final subpart HH states that facilities, prior to the point of custody transfer, that have a facilitywide actual annual average natural gas throughput less than 18.4 thousand m^3/day and a facilitywide actual annual average hydrocarbon liquid throughput less than 39,700 liter/day are exempt from subpart HH. A more detailed discussion on the development of this MSD is presented in section 2.1.1 of the BID volume 2.

Owners and operators of production facilities, after the point of custody transfer (including natural gas processing plants), must aggregate emissions from all HAP emissions units at the facility when determining whether or not the facility is a major source. Production facilities, after the point of custody transfer, are likely to have emission units in addition to glycol dehydration units and storage vessels, such as amine treaters and sulfur recovery units that are typically located at natural gas processing plants. Since these emissions units must be included in the total emissions for the facility, the EPA could not develop a cutoff that would reasonably ensure that sources operating below such a cutoff would not be major sources. Therefore, production facilities located after the point of custody transfer, including natural gas processing plants, do not qualify for the simplified major source determination.

Using the same procedure, the EPA developed an MSD for natural gas transmission and storage facilities where glycol dehydration units are the only HAP emission points. The final subpart HHH states that natural gas transmission and storage facilities operating with an actual annual average natural gas throughput below 28.3 thousand m^3/day are exempt from subpart HHH.

d. *Use of PTE Transition Policy.* Under the EPA's 1995 Potential to Emit Transition Policy, sources with low emissions (e.g., less than 50 percent of major source thresholds) may be deemed nonmajor if records of actual emissions are kept. Several commenters suggested the use of written documentation of physical and operational limitations that would be federally, State, or otherwise practically enforceable.

In the January 25, 1995 policy memorandum entitled "Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (Act)," the EPA issued a transition policy for section 112 and title V. The transition policy addressed concerns that some sources may face gaps in the ability to acquire federally enforceable PTE limits because of delays in State adoption or EPA approval of programs or in their implementation. In order to ensure that such gaps would not create adverse consequences for States or for sources, the EPA provided that, during a 2-year period extending from January 1995 through January 1997, sources lacking federally enforceable limitations, State and local air regulators had the option of treating the following types of sources as non-major under section 112 and in their title V programs: (1) sources that maintain adequate records to demonstrate that their actual emissions

are less than 50 percent of the applicable major source threshold and have continued to operate at less than 50 percent of the threshold since January 1994, and (2) sources with actual emissions between 50 and 100 percent of the major source threshold but which hold State-enforceable limits that are enforceable as a practical matter. On August 27, 1996, the transition policy was extended until July 31, 1998. On July 10, 1998, in a memorandum entitled "Second Extension of January 25, 1995 Potential to Emit Transition Policy and Clarification of Interim Policy," the EPA announced a second extension of the transition policy. The extensions were provided because the EPA is engaged in a rulemaking process to consider amendments to the current PTE requirements. Currently, the PTE rulemaking, which will address the PTE requirements in the General Provisions (40 CFR part 63, subpart A) and the title V operating permits program, has not been completed. Those rule amendments will affect federal enforceability requirements for PTE limits under these programs. Thus, there will continue to be uncertainty with respect to federally enforceable limits. Therefore, in the July 10, 1998 memorandum, the EPA extended the transition policy until December 31, 1999, or until the effective date of the final rule in the PTE rulemaking, whichever is sooner.

The EPA expects that the rulemaking will be completed before December 31, 1999, and owners and operators will have the option of complying with the PTE rulemaking as well as the procedures specified in subparts HH and HHH.

D. Glycol Dehydration Unit Process Vent Standards

The proposed standards required a 95.0 percent control efficiency for all control devices, but did not specify over which averaging period the 95.0 percent should be determined. By not specifying an averaging period, the proposed rule required continuous compliance for all control devices. The EPA received several comment letters requesting that the EPA specify an averaging period. The commenters were particularly concerned that condensers could not achieve a 95.0 percent control efficiency on a continuous basis and that additional controls would be required to ensure compliance with the 95.0 percent requirement.

The commenters' primary point was that condensers are significantly affected by changes in ambient temperature. According to the commenters, when the ambient temperature is high, the condensers are less efficient. The commenters were concerned that during the warm summer months, condensers would not meet the control requirements. Therefore, the commenters specifically requested either a 30-day or a 12-month averaging period for compliance with the control requirements to balance changes in ambient temperature. In support of this request, the commenters maintained that using a longer averaging period would create no significant change in the emissions to the environment, but would substantially decrease the number of technical violations of the standard and reduce the administrative burden for the industry and the EPA.

The EPA reviewed the control efficiency and averaging period requirements in response to these comments. Based on the Agency's review of the possible options, today's rules require 95.0 percent control as a daily average. As an alternative for owners or operators that install condensers, the EPA has modified subpart HH to allow 95.0 percent condenser control as a 365-day rolling average, based on daily average condenser efficiency as a function of condenser outlet temperature (i.e., at the end of each operating day, the owner or operator calculates the daily average condenser outlet temperature, then calculates the 365-day average control efficiency for the preceding 365 days, including the current operating day).

Based on the information collected under the authority of section 114 of the Act, the comments received during the public comment period, and site visits, the EPA believes that an averaging period shorter than 365 days is appropriate for the natural gas transmission and storage source category. To the Agency's knowledge, glycol dehydration units located at storage facilities do not typically operate throughout the year. Therefore, the EPA was concerned that it would take more than 1 calendar year for a facility to obtain 365 days of data. Additionally, glycol dehydration units located at these sources do not typically operate during the warm summer months when condenser efficiency is lower. Although transmission facilities do operate for most of the year, the EPA believes that the HAP emission units in operation at these facilities are primarily compressors, and that most glycol dehydration units located at these facilities are used for withdrawing natural gas from storage (i.e., not likely to operate year-round). Therefore, for condensers installed on glycol dehydration units subject to control requirements under subpart HHH, the EPA has modified the requirements to specify that owners or operators that install condensers have the option of meeting a 95.0 percent control efficiency as a 30-day rolling average.

Several commenters requested that the EPA allow for combinations of controls and process modifications to achieve the required control efficiency. The commenters provided several suggestions for modifying the language in § 63.765(c)(2) stating that the owner or operator could reduce emissions from the glycol dehydration unit by 95.0 percent through process modifications or process modifications with controls. In addition, one of the suggestions was to include language allowing the owner or operator to complete a one-time compliance demonstration for the process modification.

The EPA agrees that owners or operators should be allowed to achieve a 95.0 percent emission reduction using process modifications or combinations of process modifications and one or more control devices. Therefore, today's rules contain requirements for demonstrating compliance with a 95.0 percent emission reduction using process modifications or a combination of process modifications and one or more control devices. In particular, the final rule requires the owner or operator to demonstrate how emissions have been reduced and to what level, and that the facility continues to be operated such that the 95.0 percent emission reduction is maintained.

The EPA does not believe that a one-time compliance demonstration would ensure future or continuous compliance, and the EPA believes that it is not appropriate. Therefore, the EPA has not included the commenter's suggested language allowing a one-time compliance demonstration for process modification. Instead, the final rules require the owner or operator to document facility operations and to provide this information in the Periodic reports.

E. Storage Vessel Standards

The criteria for an API gravity equal to or greater than 40 degrees or an initial producing GOR equal to or greater than 0.31 m3/liter were used in the proposed rule to define storage vessels with the potential for flash emissions. Prior to proposal, the EPA's analysis of storage vessels that contain hydrocarbon liquids that have an API gravity or an initial producing GOR higher than these criteria indicated the potential for significant flash emissions.

The EPA received comment letters objecting to the proposed cutoffs for storage vessels with the potential for flash emissions. In order to demonstrate their objection to the technical basis for these exemption criteria, the commenters provided emissions estimates for tanks containing hydrocarbon liquids with an API gravity less than 40 degrees and GOR of less than 0.31 m^3/liter. According to the emission estimates, these tanks, which do not meet the criteria for a storage vessel with the potential for flash emissions and would be exempt from the storage vessel control requirements, had significant HAP emissions. The EPA also received emission estimates for a tank containing a hydrocarbon liquid with an API gravity greater than 40 degrees and a GOR greater than 0.31 m^3/liter. According to the analysis provided by the commenter, this tank would be subject to the storage vessel control requirements but had no flash emissions.

The commenters did not provide alternative suggestions for defining storage vessels with the potential for flash emissions, other than recommending that "the proposed storage tank exemption/control criteria be based on credible engineering methods supported by fundamental principles of fluid phase behavior."

The EPA developed the definition for storage vessels with the potential for flash emissions based on criteria (i.e., API gravity and GOR) that were easily recognized by industry personnel and relatively easy to obtain. Furthermore, these criteria are based on hydrocarbon liquid characteristics.

According to section 112(d)(1), the Administrator is required to establish emission standards for each category of major sources. Section 112(d)(1) states that "[T]he Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards * * *." Furthermore, section 112(d)(3) states that emission standards for existing sources in a category may be no less stringent than the MACT floor.

As stated in section V.C.1 of this preamble, the EPA has established that among the class of sources referred to as black oil facilities, the MACT floor is no control. For the class of sources defined as storage vessels with the potential for flash emissions (which includes storage vessels that do not process black oil), the EPA evaluated "* * * the average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information) * * *" (section 112(d)(3)(A) of the Act). The EPA determined that the top 12 percent of existing storage vessels with the potential for flash emissions were controlled.

The EPA recognizes that there could be specific situations, such as the ones analyzed by the commenters, where emissions of an exempted stream are higher than those of a non-exempted stream. In addition, there are many factors that affect whether flash emissions occur (e.g., pressure drop between two tanks, liquid vapor pressure, etc.). However, the EPA believes that this approach identifies hydrocarbon liquids that have a potential for significant flash emissions under conditions representative of industry operations.

In today's rule (final subpart HH), the EPA has added the throughput cutoff criterion to the storage vessels with the potential for flash emissions definition. The final rule states that a storage vessel with the potential for flash emissions is defined as a storage vessel that contains a hydrocarbon liquid with a stock tank GOR equal to or greater than 0.31 m3/liter and an API gravity equal to or greater than 40 degrees, and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liter/day. By adding the throughput criterion to the definition of storage vessels with the potential for flash emissions, rather than as a cutoff specified in proposed § 63.764(c)(2), storage vessels that do not meet the criteria for a storage vessel with the potential for flash emissions are not considered affected sources in the final rule and are not included in a facility's PTE calculation for determining major source status. The EPA believes that based on representative industry operations, the 40 degrees, 0.31 m^3/liter and the 79,500-liter/day exemption criteria are appropriate for defining storage vessels with the potential for flash emissions.

F. Standards for Natural Gas Transmission and Storage

The EPA received several comment letters expressing concern for the EPA's proposed standard for the natural gas transmission and storage source category. The commenters stated that the EPA did not have sufficient data to develop standards for the natural gas transmission and storage source category. The commenters requested that the EPA delay the natural gas transmission and storage portion of the proposed rulemaking to properly survey the industry for more meaningful data and assess whether a standard for the natural gas transmission and storage source category is necessary or achievable.

Several commenters explained that a review of the background information for proposed subpart HHH showed that the database consisted of information on the methods used in natural gas transmission from only two companies and no underground storage facilities. The commenters noted that the companies surveyed were predominately oil production facilities that handled gas as a by-product of oil production and that have higher HAP emissions because they handle more liquids with higher concentrations of HAP.

In response to these comments, the EPA collected additional data on glycol dehydration units in the natural gas transmission and storage source category through site visits and requests for information under the authority of section 114 of the Act.

Through these site visits and survey questionnaires, the EPA collected information from 83 facilities in the natural gas transmission and storage source category. The EPA considered this new information, along with the previously collected information on the natural gas transmission and storage source category, in developing a MACT floor for existing and new process vents on glycol dehydration units located at facilities in this source category. The EPA also used this information to better characterize processes and operations at natural gas transmission and storage facilities.

As stated in the January 15, 1999 supplemental notice (64 FR 2611), the additional data supported a MACT floor of 95.0 percent for existing and new natural gas transmission and storage facilities. In addition, the EPA announced that the Agency was considering raising the proposed throughput cutoff of 85 thousand m^3/day to 283 thousand m^3/day on an actual annual average basis. Glycol dehydration units operating below this cutoff would not be required to install controls under subpart HHH. The data did not warrant a change in the benzene emission cutoff of 0.90 Mg/yr.

The public comment period closed on February 16, 1999. The EPA received four comment letters in response to the EPA's request for comments and supporting information on the consideration of a 95.0 percent HAP emission reduction as the floor level of control, on the 283 thousand m^3/day natural gas throughput cutoff and the 0.90-Mg/yr benzene emission cutoff. The commenters agreed that exempting glycol dehydration units with actual annual average natural gas throughputs

less than 283 thousand 78m³/day and with actual average benzene emissions less than 0.90 Mg/yr from the control requirements under subpart HHH was appropriate.

However, the commenters indicated that they did not agree with a MACT floor of 95.0 percent for the transmission and storage source category. The commenters requested that the final rule should either exempt existing sources controlled by condensers, or require that existing sources controlled with condensers be controlled to a different level (i.e., 70 percent) than the combustion technology-based MACT floor. The commenters stated that condensers could consistently achieve a 75 percent emission reduction and that requiring an additional 20 percentage points of emission reduction in HAP would be inconsistent with the cost-to-benefit analysis in the February 6, 1998 proposal.

The EPA does not believe that it is necessary to provide exemptions or alternative levels of control for existing glycol dehydration units that are controlled by condensers. The EPA believes that this would not be consistent with the Act, which specifies in section 112(d)(3) that for a source category with 30 or more sources (such as the transmission and storage source category), the MACT floor for existing sources shall not be less stringent than "* * * the average limitation achieved by the best performing 12 percent of the existing sources * * *." The data collected by the EPA indicated that the average limitation achieved by the top 12 percent of the existing glycol dehydration units located at natural gas transmission and storage facilities was 95.0 percent. Furthermore, the data indicated that the top 12 percent of the existing glycol dehydration units were controlled using combustion or a combination of combustion and condensation. Therefore, in accordance with the statute, the EPA established the MACT floor to be 95.0 percent for glycol dehydration units located at natural gas transmission and storage facilities, which corresponds to combustion.

However, the EPA agrees that the supplemental notice did not address the issue of averaging period for condensers in use at transmission and storage facilities. As stated in this preamble, the final rule allows an owner or operator that installs a condenser for control of HAP from glycol dehydration unit process vents to establish compliance with the 95.0 percent HAP emission reduction on a 30-day rolling average. In addition, the final rule allows the owner or operator to comply with one of the following: (1) 95.0 percent HAP emission reduction, (2) 20 ppmv outlet HAP concentration for combustion devices, or (3) outlet emissions of 0.90 Mg/yr of benzene. The EPA believes that the 0.90 Mg/yr benzene emission limit and the 30-day averaging period for condensers provides sufficient flexibility for owners and operators of existing controlled glycol dehydration units. A more detailed discussion regarding the EPA's responses to the comments received on the supplemental notice are presented in the BID volume 2.

G. Monitoring, Recordkeeping, and Reporting Requirements

The EPA received several comment letters claiming that the recordkeeping and reporting requirements of the proposed rule were extremely burdensome. The commenters requested that the EPA reduce the monitoring, recordkeeping, and reporting burden associated with the proposed rule. In particular, commenters were concerned that remote and unmanned facilities would be overburdened by the proposed monitoring, recordkeeping and reporting requirements. Commenters also requested that provisions be added to the rule to avoid duplicative reporting. Other commenters requested that flexibility to allow alternative monitoring, recordkeeping, and reporting be incorporated into the final rule.

The EPA recognizes that unnecessary monitoring, recordkeeping, and reporting requirements would burden both the source and enforcement agencies. Prior to proposal, the EPA attempted to reduce the amount of monitoring, recordkeeping, and reporting to only that which is necessary to demonstrate compliance.

Although the EPA has not removed the monitoring requirements for unmanned or remote facilities, the EPA did evaluate the possibility of reducing the requirements for unmanned facilities. The EPA concluded, however, that the monitoring requirements are the minimum necessary to ensure that control devices are operating to ensure compliance.

The EPA reevaluated whether monitoring, recordkeeping, and reporting requirements could be further reduced while maintaining the enforceability of the rule. Therefore, the EPA has made the following changes in the promulgated rule to further reduce the monitoring, recordkeeping, and reporting burden.

(1) Almost all reports have been consolidated into the Notification of Compliance Status report and the Periodic reports.

(2) If multiple tests are conducted for the same kind of emission point, using the same test method, only one complete test report is required to be submitted along with the summaries of the results of other tests.

(3) Site-specific test plans describing quality assurance in § 63.7(c) of 40 CFR part 63, subpart A, are not specifically required in the individual subparts because the test methods cited in subparts HH and HHH already contain applicable quality assurance protocols. It should be noted that the Administrator would still have the authority to request a test plan.

(4) Periodic reports are required to be submitted semiannually for all facilities (the proposal required quarterly reports if monitored parameters were out of range more than a specified percentage of time).

(5) A reduction in the record retention requirements for monitored parameters. The proposal required values of monitored parameters to be recorded every 15 minutes and all 15-minute records had to be retained. The final rule requires monitored parameters to be recorded every hour and all hourly records to be retained.

Several commenters were concerned with the provisions specifying the accuracy of the measurement devices used to comply with the subpart and requested that the EPA change or remove the accuracy requirements.

The EPA believes that accuracy requirements are necessary to demonstrate ongoing compliance. Furthermore, if the accuracy requirements were removed, additional recordkeeping and reporting requirements would be necessary to ensure that less accurate monitors were not installed after the performance tests. However, the EPA agrees with the commenters that the accuracy levels could be slightly less restrictive. Therefore, the EPA has changed the accuracy levels from ±1 percent of the temperature being monitored, in °C or ±0.5 °C, to ±2 percent of the temperature being monitored, in °C or ±2.5 °C, whichever is greater.

H. Cost and Economic Impacts

The EPA specifically requested comments on the cost impact and the production recovery credits as discussed in section IV of the preamble to the proposal (63 FR 6297), along with supporting documentation. The EPA received comment letters stating that the EPA had underestimated the costs of controls, had underestimated the cost of treating produced water, and had

overstated the quantity of product recovered that could be sold to offset the costs associated with subpart HH. Of specific concern was the closure of smaller facilities due to the rule.

The EPA based its cost estimates for control devices on published installed control system costs from the Ventura County (California) Air Pollution Control District (APCD) (Air Docket A-94-04). These costs were associated with a glycol dehydration unit regulation issued by the Ventura County APCD. According to this information, the cost of installing a condenser control system does not vary significantly based on the size (capacity) of a glycol dehydration system.

Approximately 20 billion barrels per year of produced water are generated by the oil and natural gas production source category (Air Docket A-94-04). Using an emission model developed by the Gas Research Institute (GRI-GLYCalc, version 3.0) to determine the amount of produced water generated by the number of facilities estimated to be affected by subpart HH, the EPA calculated that the oil and natural gas production NESHAP would result in an increase in produced water production of approximately 590,000 barrels per year. A GRI report (GRI Publication Number GRI-96/0049) indicated that produced water would be typically handled along with other produced water streams, either by underground injection control, surface impoundment, or other miscellaneous methods. Thus, the EPA believes that the final NESHAP would have a minimal impact on existing produced water disposal costs and that the estimated NESHAP control costs are, therefore, reasonable.

The EPA based its national cost estimate impacts on the estimated number of facilities that would be impacted by the regulatory provisions of subparts HH and HHH, along with detailed emission control cost estimates per HAP emission point (Air Docket A-94-04). In addition, the monitoring, recordkeeping, and reporting (MRR) costs were based on a detailed analysis of the regulatory requirements of subparts HH and HHH. The EPA currently believes that the MRR cost estimates accurately reflect the estimated effort required to address MRR requirements in the final NESHAP.

Further, the EPA expects that the 85 thousand m^3/day size cutoff will prevent the premature closure of a large number of small and often marginal well operations. Not accounting for this size cutoff would contribute to differences in the estimated reduction in natural gas production and employment losses associated with the standards.

As described in Section 4 of the economic impact analysis report, the EPA's economic model determines production and closure decisions on the basis of a producing field (i.e., a group of similar wells) that is consistent with commenters concerns that "production decisions are made on a well-by-well or project basis and if an individual project's profits fall below its break-even point, that the well will be abandoned." The EPA did not estimate losses of economically producible natural gas reserves. The economic analysis conducted by the EPA is unable to address possible impacts on production from future natural gas reserves. However, based on the negligible impact on current natural gas production associated with the EPA's engineering estimate of compliance cost, it is not expected that these impacts would be as great as indicated by the commenter.

VI. Administrative Requirements

A. Docket

The docket for these rulemakings is A-94-04. The docket is an organized and complete file of all the information considered by the EPA in the development of these rulemakings. The principal purposes of the docket are (1) to allow interested parties a means to identify and locate documents so that they can effectively participate in the rulemaking process and (2) to serve as the record in case of judicial review (except for interagency review materials) [section 307(d)(7)(A) of the Act]. This docket contains copies of the regulatory texts, BID volumes 1 and 2, references not readily available to the public, and technical memoranda documenting the information considered by the EPA in the development of the rules. The docket is available for public inspection at the EPA's Air and Radiation Docket and Information Center, the location of which is given in the **ADDRESSES** section of this notice.

B. Paperwork Reduction Act

The information collection requirements in these rules have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Information collection request (ICR) documents have been prepared by the EPA (ICR Nos. 1788.02 and 1789.02) and copies may be obtained from Sandy Farmer, OPPE Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M Street, SW; Washington, DC 20460 or by calling (202) 260-2740. The information requirements are not effective until OMB approves them.

Information is required to ensure compliance with the provisions of the final rules. If the relevant information were collected less frequently, the EPA would not be reasonably assured that a source is in compliance with the final rules. In addition, the EPA's authority to take administrative action would be reduced significantly.

The final rules require that facility owners or operators retain records for a period of 5 years, which exceeds the 3 year retention period contained in the guidelines in 5 CFR 1320.6. The 5 year retention period is consistent with the provisions of the General Provisions of 40 CFR part 63, and with the 5 year records retention requirement in the operating permit program under title V of the Act.

All information submitted to the EPA for which a claim of confidentiality is made will be safeguarded according to the EPA policies set forth in title 40, chapter 1, part 2, subpart B, Confidentiality of Business Information. See 40 CFR part 2; 41 FR 36902, September 1, 1976; amended by 43 FR 3999, September 8, 1978; 43 FR 42251, September 28, 1978; and 44 FR 17674, March 23, 1979. Even where the EPA has determined that data received in response to an ICR are eligible for confidential treatment under 40 CFR part 2, subpart B, the EPA may nonetheless disclose the information if it is "relevant in any proceeding" under the statute (42 U.S.C. 7414(C); 40 CFR 2.301(g)). The information collection complies with the Privacy Act of 1974 and OMB Circular 108.

Information to be reported consists of emission data and other information that are not of a sensitive nature. No sensitive personal or proprietary data are being collected.

The estimated annual average hour burden for the final oil and natural gas production NESHAP is 56 hours per respondent. The estimated annual average cost of this burden is $2,400 for each of the estimated 484 existing and new (projected) respondents.

The estimated annual average hour burden for the final natural gas transmission and storage NESHAP is 30 hours per respondent. The estimated annual average cost of this burden is $1,300 for each of the estimated 7 existing respondents.

Reports are required on a semiannual basis and as required, as in the case of startup, shutdown, and malfunction plans. 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; to 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; to adjust the existing ways to comply with any previously applicable instructions and requirements; to train personnel to be able to respond to a collection of information; to search data sources; to 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 the EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15. The EPA is amending the table in 40 CFR part 9 of currently approved ICR control numbers issued by OMB for various regulations to list the information requirements contained in these final rules.

C. Executive Order 12866: A Significant Regulatory Action Determination

Under Executive Order 12866, "Regulatory Planning and Review," (58 FR 5173 (October 4, 1993)), the EPA must determine whether the regulatory action is "significant" and therefore subject to OMB review and the requirements of the Executive Order. The criteria set forth in section 1 of the Order for determining whether a regulation is a significant rule are as follows: (1) is likely to have an annual effect on the economy of $100 million or more, or adversely and materially affect a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local or tribal governments or communities; (2) is likely to create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) is likely to materially alter the budgetary impact of entitlements, grants, user fees or loan programs, or the rights and obligations of recipients thereof; or (4) is likely to raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to Executive Order 12866, OMB has reviewed these rules. Changes made in response to OMB suggestions or recommendations are documented in the public record.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions. These final rules will not have a significant economic impact on a substantial number of small entities. According to *Wards Business Directory* (1993), there are 1,152 firms in the seven affected Standard Industrial Classification (SIC) codes and 735 of these firms meet the Small Business Administration (SBA) definition of a small entity.

The number of affected small entities for these rules is likely to be minimal due to several considerations in these rules that minimize the burden on all firms, both small and large. These considerations include exempting from the control requirements of the oil and natural gas production NESHAP those glycol dehydration units located at major sources with (1) an actual flowrate of natural gas to the glycol dehydration unit less than 85 thousand m^3/day, on an annual average basis, or (2) benzene emissions less than 0.90 Mg/yr. Also, these considerations include exempting from the control requirements of the natural gas transmission and storage NESHAP those glycol dehydration units located at major sources with (1) an actual flowrate of natural gas to the glycol dehydration unit less than 283 thousand m^3/day, on an annual average basis; or (2) benzene emissions less than 0.90 Mg/yr.

In a screening of potential impacts on a sample of small entities, the EPA found that there are minimal impacts on these entities. The weighted average of control costs as a percent of sales is 0.09 of 1 percent for the small firms in the sample, while a maximum value of 1.1 percent results for only two of these firms. The analysis also indicates that with the regulations, the change in measures of profitability are minimal (i.e., 0.11 of 1 percent change in the cost-to-sales ratio for small firms), and there are no indications of financial failures or employment losses for both small and large firms. The screening analysis for these rules is detailed in the Economic Impact Analysis (see Docket No. A-94-04).

E. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective June 17, 1999.

F. Unfunded Mandates Reform Act

Title II of the Unfunded Mandate Reform Act of 1995 (UMRA), Pub. L. 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, the 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 the 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 the 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 the 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 the EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

The EPA has determined that today's final rules do not include a Federal mandate that may result in expenditures of $100 million of more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Therefore, the requirements of the Unfunded Mandates Reform Act do not apply to today's final rules.

G. Executive Order 12875: Enhancing the Intergovernmental Partnership

Under Executive Order 12875, the EPA may not issue a regulation that is not required by statute and that creates a mandate upon a State, local or tribal government unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by those governments, or the EPA consults with those governments. If the EPA complies by consulting, Executive Order 12875 requires the EPA to provide OMB a description of the extent of the EPA's prior consultation with representatives of affected State, local and tribal governments, the nature of their concerns, copies of any written communications from the governments, and a statement supporting the need to issue the regulation. In addition, Executive Order 12875 requires the EPA to develop an effective process permitting elected officials and other representatives of State, local and tribal governments to provide meaningful and timely input in the development of regulatory proposals containing significant unfunded mandates.

Today's rules do not create a mandate on the State, local or tribal governments. These rules do not impose any enforceable duties on these entities. Accordingly, the requirements of Section 1(a) of Executive Order 12875 do not apply to these rules. The EPA, nevertheless, involved State and local governments in their development of the final rules.

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

Executive Order 13045, "Protection of Children from Environmental Health Risks and Safety Risks," (62 FR 19885, April 23, 1997) applies to any rule that: (1) the EPA determines is economically significant as defined under Executive Order 12866, (2) concerns an environmental health or safety risks, and (3) the EPA has any reason to believe may disproportionately affect children. If the regulatory action meets these criteria, the EPA 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 EPA.

The 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. These rules are not subject to Executive Order 13045 for two reasons: (1) the rule is based solely on technology performance; and (2) no alternative technologies have been identified that would provide greater stringency at a reasonable cost, therefore, an assessment of impacts on children would have no impact on the stringency decision.

I. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13084, the EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities unless the Federal Government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments, or the EPA consults with those governments. If the EPA complies by consulting, Executive Order 13084 requires the EPA to provide to OMB, in a separately identified section of the preamble to the rule, a description of the extent of the EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires the EPA to develop an effective process permitting elected officials and other representatives of Indian tribal governments "to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities."

Today's rules do not significantly or uniquely affect the communities of Indian tribal governments. The final rules do not create mandates upon tribal governments. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to these rules.

J National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA), Pub. L. 104-113 (March 7, 1996), directs all Federal agencies to use voluntary consensus standards in regulatory and procurement activities unless doing so would be inconsistent with applicable law or otherwise impracticable. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA requires Federal agencies to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards. This section summarizes the EPA's response to the requirements of the NTTAA for the analytical and test methods required by this final rule.

Consistent with the NTTAA, the EPA conducted a search to identify voluntary consensus standards. The search identified 16 voluntary consensus standards that appeared to have possible use in lieu of EPA standard reference methods. However, after reviewing available standards, the EPA determined that eight of the candidate consensus standards identified for measuring HAP or surrogate pollutant emissions subject to the emission standards in the rule would not be practical due to lack of equivalency, documentation, validation data and other important technical and policy considerations. Seven of the remaining candidate consensus standards are new standards under development that the EPA plans to follow, review, and consider adopting at a later date.

One consensus standard, ASTM Z7420Z, is potentially practical for EPA use in lieu of EPA Method 18 (See 40 CFR part 60, appendix A). At the time of the EPA's search, the ASTM standard was still under development and the EPA had provided comments on the method. The EPA also compared a draft of this ASTM standard to methods previously reviewed as alternatives to EPA Method 18 that were approved with specific applicability limitations. These methods are designated as ALT-017 and CTM-028 and available through EPA's Emission Measurement Center Internet site at www.epa.gov/ttn/emc/tmethods.html. The proposed ASTM Z7420Z standard is very similar to these approved alternative methods. When finalized and adopted by ASTM, the standard may be equally suitable for the same applications as the approved

alternatives. However, this rule does not adopt the ASTM standard since it is not practical to do so until the potential candidate is final and the EPA has review the final standard. The EPA plans to continue to follow the progress of the standard and will consider adopting the ASTM standard at a later date.

Similarly, the Gas Research Institute has developed a sampling method for glycol dehydration units, the "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1). The development of this procedure included a field evaluation program and technical review by the EPA. A report documenting this procedure has been available to the public from the GRI since 1996. This procedure provides a simpler, cheaper, and technically appropriate means of determining HAP emissions from glycol dehydration unit process vents when direct measurement is necessary. Consistent with the Agency's commitment to reduce costs to the private sector where technically feasible and in accordance with Clean Air Act requirements, the EPA has included the "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" as an alternative control device performance test procedure.

This rule requires standard EPA methods known to the industry and States. Approved alternative methods also may be used with prior EPA approval.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous air pollutants, Black oil, Associated equipment, Storage vessels with the potential for flash emissions, Glycol dehydration units, Oil and natural gas production, Natural gas transmission and storage, Equipment leaks, Natural gas processing plant, Reporting and recordkeeping requirements.

Dated: May 14, 1999.

Carol M. Browner,

Administrator.

For the reasons set out in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*, as amended by Pub. L. 101-549, 104 Stat. 2399.

2. Part 63 is amended by adding subpart HH to read as follows:

Subpart HH—National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities

Sec.

63.760 Applicability and designation of affected source.
63.761 Definitions.
63.762 Startups, shutdowns, and malfunctions.
63.763 [Reserved]
63.764 General standards.
63.765 Glycol dehydration unit process vent standards.
63.766 Storage vessel standards.
63.767 [Reserved]
63.768 [Reserved]
63.769 Equipment leak standards.
63.770 [Reserved]
63.771 Control equipment requirements.
63.772 Test methods, compliance procedures, and compliance determinations.
63.773 Inspection and monitoring requirements.
63.774 Recordkeeping requirements.
63.775 Reporting requirements.
63.776 Delegation of authority.
63.777 Alternative means of emission limitation.
63.778 [Reserved]
63.779 [Reserved]
Appendix to Subpart HH—Tables

Subpart HH—National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities

§ 63.760 Applicability and designation of affected source.

(a) This subpart applies to the owners and operators of the emission points, specified in paragraph (b) of this section that are located at oil and natural gas production facilities that meet the specified criteria in paragraphs (a)(1) and either (a)(2) or (a)(3) of this section.

(1) Major sources of hazardous air pollutants (HAP) as determined using the maximum natural gas or hydrocarbon liquid throughput, as appropriate, calculated in paragraphs (a)(1)(i) through (a)(1)(iii) of this section. A facility that is determined to be an area source based on emission estimates using the maximum natural gas or hydrocarbon throughput calculated as specified in paragraphs (a)(1)(i) through (iii) of this section, but subsequently increases emissions or potential to emit above the major source levels (without first obtaining and complying with other limitations that keep its potential to emit HAP below major source levels), becomes a major source and must comply thereafter with all applicable provisions of this subpart starting on the applicable compliance date specified in paragraph (f) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

(i) If the owner or operator documents, to the Administrator's satisfaction, a decline in annual natural gas or hydrocarbon liquid throughput, as appropriate, each year for the 5 years prior to June 17, 1999, the owner or operator shall calculate the maximum natural gas or hydrocarbon liquid throughput used to determine maximum potential emissions according to the requirements specified in paragraph (a)(1)(i)(A) of this section. In all other circumstances, the owner or operator shall calculate the maximum throughput used to determine whether a facility is a major source in accordance with the requirements specified in paragraph (a)(1)(i)(B) of this section.

(A) The maximum natural gas or hydrocarbon liquid throughput is the average of the annual natural gas or hydrocarbon liquid throughput for the 3 years prior to June 17, 1999, multiplied by a factor of 1.2.

(B) The maximum natural gas or hydrocarbon liquid throughput is the highest annual natural gas or hydrocarbon liquid throughput over the 5 years prior to June 17, 1999, multiplied by a factor of 1.2.

(ii) The owner or operator shall maintain records of the annual facility natural gas or hydrocarbon liquid throughput each year and upon request submit such records to the Administrator. If the facility annual natural gas or hydrocarbon liquid throughput increases above the maximum natural gas or hydrocarbon liquid throughput calculated in paragraph (a)(1)(i)(A) or (a)(1)(i)(B) of this section, the maximum natural gas or hydrocarbon liquid throughput must be recalculated using the higher throughput multiplied by a factor of 1.2.

(iii) The owner or operator shall determine the maximum values for other parameters used to calculate emissions as the maximum for the period over which the maximum natural gas or hydrocarbon liquid throughput is determined in accordance with paragraph (a)(1)(i)(A) or (B) of this section. Parameters shall be based on either highest measured values or annual average.

(2) Facilities that process, upgrade, or store hydrocarbon liquids prior to the point of custody transfer.

(3) Facilities that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas

transmission and storage source category or is delivered to a final end user. For the purposes of this subpart, natural gas enters the natural gas transmission and storage source category after the natural gas processing plant, when present. If no natural gas processing plant is present, natural gas enters the natural gas transmission and storage source category after the point of custody transfer.

(b) The affected sources to which the provisions of this subpart apply shall comprise each emission point located at a facility that meets the criteria specified in paragraph (a) of this section and listed in paragraphs (b)(1) through (4) of this section.

(1) Each glycol dehydration unit;

(2) Each storage vessel with the potential for flash emissions;

(3) The group of all ancillary equipment, except compressors, intended to operate in volatile hazardous air pollutant service (as defined in § 63.761), which are located at natural gas processing plants; and

(4) Compressors intended to operate in volatile hazardous air pollutant service (as defined in § 63.761), which are located at natural gas processing plants.

(c) [Reserved]

(d) The owner and operator of a facility that does not contain an affected source as specified in paragraph (b) of this section are not subject to the requirements of this subpart.

(e) *Exemptions.* The facilities listed in paragraphs (e)(1) and (e)(2) of this section are exempt from the requirements of this subpart. Records shall be maintained as required in § 63.10(b)(3).

(1) A facility that exclusively processes, stores, or transfers black oil (as defined in § 63.761) is not subject to the requirements of this subpart. For the purposes of this subpart, a black oil facility that uses natural gas for fuel or generates gas from black oil shall qualify for this exemption.

(2) A facility, prior to the point of custody transfer, with a facilitywide actual annual average natural gas throughput less than 18.4 thousand standard cubic meters per day and a facilitywide actual annual average hydrocarbon liquid throughput less than 39,700 liters per day.

(f) The owner or operator of an affected source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(1) and (f)(2) of this section.

(1) The owner or operator of an affected source, the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with provisions of this subpart no later than June 17, 2002 except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) The owner or operator of an affected source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

(g) The following provides owners or operators of an affected source with information on overlap of this subpart with other regulations for equipment leaks. The owner or operator shall document that they are complying with other regulations by keeping the records specified in § 63.774(b)(9).

(1) After the compliance dates specified in paragraph (f) of this section, ancillary equipment and compressors that are subject to this subpart and that are also subject to and controlled under the provisions of 40 CFR part 60, subpart KKK, are only required to comply with the requirements of 40 CFR part 60, subpart KKK.

(2) After the compliance dates specified in paragraph (f) of this section, ancillary equipment and compressors that are subject to this subpart and are also subject to and controlled under the provisions of 40 CFR part 61, subpart V, are only required to comply with the requirements of 40 CFR part 61, subpart V.

(3) After the compliance dates specified in paragraph (f) of this section, ancillary equipment and compressors that are subject to this subpart and are also subject to and controlled under the provisions of 40 CFR part 63, subpart H, are only required to comply with the requirements of 40 CFR part 63, subpart H.

(h) An owner or operator of an affected source that is a major source or is located at a major source and is subject to the provisions of this subpart is also subject to 40 CFR part 70 or part 71 operating permit requirements.

§ 63.761 Definitions.

All terms used in this subpart shall have the meaning given them in the Clean Air Act (Act), subpart A of this part (General Provisions), and in this section. If the same term is defined in subpart A and in this section, it shall have the meaning given in this section for purposes of this subpart.

Alaskan North Slope means the approximately 180,000 square kilometer area (69,000 square mile area) extending from the Brooks Range to the Arctic Ocean.

Ancillary equipment means any of the following pieces of equipment: pumps, pressure relief devices, sampling connection systems, open-ended valves, or lines, valves, flanges, or other connectors.

API gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Associated equipment, as used in this subpart and as referred to in section 112(n)(4) of the Act, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the wellbore to the point of custody transfer, except glycol dehydration units and storage vessels with the potential for flash emissions.

Black oil means hydrocarbon (petroleum) liquid with an initial producing gas-to-oil ratio (GOR) less than 0.31 cubic meters per liter and an API gravity less than 40 degrees.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting thermal energy in the form of steam or hot water. Boiler also means any industrial furnace as defined in 40 CFR 260.10.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system shall not be considered a closed-vent system and is not subject to closed-vent system standards.

Combustion device means an individual unit of equipment, such as a flare, incinerator, process heater, or boiler, used for the combustion of organic HAP emissions.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and

remains liquid at standard conditions, as specified in § 63.2.

Continuous recorder means a data recording device that either records an instantaneous data value at least once every hour or records hourly or more frequent block average values.

Control device means any equipment used for recovering or oxidizing HAP or volatile organic compound (VOC) vapors. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (i.e., injected into the flame zone of a combustion device), returned back to the process, or sold, then the recovery system used, including piping connections, and flow inducing devices, is not considered to be control devices or closed-vent systems.

Cover means a device which is placed on top of or over a material such that the entire surface area of the material is enclosed and sealed. A cover may have openings (such as access hatches, sampling ports, and gauge wells) if those openings are necessary for operation, inspection, maintenance, or repair of the unit on which the cover is installed, provided that each opening is closed and sealed when the opening is not in use. In addition, a cover may have one or more safety devices. Examples of a cover include, but are not limited to, a fixed-roof installed on a tank, an external floating roof installed on a tank, and a lid installed on a drum or other container.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Equipment leaks means emissions of HAP from ancillary equipment (as defined in this section) and compressors.

Facility means any grouping of equipment where hydrocarbon liquids are processed, upgraded (i.e., remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For the purpose of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Field natural gas means natural gas extracted from a production well prior to entering the first stage of processing such as dehydration.

Fixed-roof means a cover that is mounted on a storage vessel in a stationary manner and that does not move with fluctuations in liquid level.

Flame zone means the portion of the combustion chamber in a combustion device occupied by the flame envelope.

Flash tank. See the definition for gas-condensate-glycol (GCG) separator.

Flow indicator means a device which indicates whether gas flow is present in a line or whether the valve position would allow gas flow to be present in a line.

Gas-condensate-glycol (GCG) separator means a two- or three-phase separator through which the "rich" glycol stream of a glycol dehydration unit is passed to remove entrained gas and hydrocarbon liquid. The GCG separator is commonly referred to as a flash separator or flash tank.

Gas-to-oil ratio (GOR) means the number of standard cubic meters of gas produced per liter of crude oil or other hydrocarbon liquid.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

Glycol dehydration unit baseline operations means operations representative of the glycol dehydration unit operations as of June 17, 1999. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (i.e., at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

Glycol dehydration unit process vent means either the glycol dehydration unit reboiler vent and the vent from the GCG separator (flash tank), if present.

Glycol dehydration unit reboiler vent means the vent through which exhaust from the reboiler of a glycol dehydration unit passes from the reboiler to the atmosphere or to a control device.

Hazardous air pollutants or *HAP* means the chemical compounds listed in section 112(b) of the Clean Air Act. All chemical compounds listed in section 112(b) of the Act need to be considered when making a major source determination. Only the HAP compounds listed in Table 1 of this subpart need to be considered when determining compliance.

Hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

In VHAP service means that a piece of ancillary equipment or compressor either contains or contacts a fluid (liquid or gas) which has a total volatile HAP (VHAP) concentration equal to or greater than 10 percent by weight as determined according to the provisions of § 63.772(a).

In wet gas service means that a piece of equipment contains or contacts the field gas before the extraction of natural gas liquids.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. Any energy recovery section is not physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section is a separate section following the combustion section and the two are joined by ducts or connections carrying flue gas. The above energy recovery section limitation does not apply to an energy recovery section used solely to preheat the incoming vent stream or combustion air.

Initial producing GOR means the producing standard cubic meters of gas per liter at the time that the reservoir pressure is above the bubble point pressure (or dewpoint pressure for a gas).

Initial startup means the first time a new or reconstructed source begins production. For the purposes of this subpart, initial startup does not include subsequent startups (as defined in this section) of equipment, for example, following malfunctions or shutdowns.

Major source, as used in this subpart, shall have the same meaning as in § 63.2, except that: (1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control; (2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and (3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage tanks with flash emission potential shall be aggregated for a major source determination.

Natural gas means a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface. The principal hydrocarbon constituent is methane.

Natural gas liquids (NGL) means the liquid hydrocarbons, such as ethane, propane, butane, pentane, natural gasoline, and condensate that are extracted from field natural gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, or the fractionation of mixed NGL to natural gas products, or a combination of both.

No detectable emissions means no escape of HAP from a device or system to the atmosphere as determined by:

(1) Instrument monitoring results in accordance with the requirements of § 63.772(c); and

(2) The absence of visible openings or defects in the device or system, such as rips, tears, or gaps.

Operating parameter value means a minimum or maximum value established for a control device or process parameter which, if achieved by itself or in combination with one or more other operating parameter values, indicates that an owner or operator has complied with an applicable operating parameter limitation, over the appropriate averaging period as specified in § 63.772(f) or (g).

Operating permit means a permit required by 40 CFR part 70 or part 71.

Organic monitoring device means an instrument used to indicate the concentration level of organic compounds exiting a control device based on a detection principle such as infra-red, photoionization, or thermal conductivity.

Primary fuel means the fuel that provides the principal heat input (i.e., more than 50 percent) to the device. To be considered primary, the fuel must be able to sustain operation without the addition of other fuels.

Process heater means an enclosed device using a controlled flame, the primary purpose of which is to transfer heat to a process fluid or process material that is not a fluid, or to a heat transfer material for use in a process (rather than for steam generation).

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Production field facilities means those facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the drive shaft.

Relief device means a device used only to release an unplanned, non-routine discharge in order to avoid safety hazards or equipment damage. A relief device discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

Safety device means a device that meets both of the following conditions: it is not used for planned or routine venting of liquids, gases, or fumes from the unit or equipment on which the device is installed; and it remains in a closed, sealed position at all times except when an unplanned event requires that the device open for the purpose of preventing physical damage or permanent deformation of the unit or equipment on which the device is installed in accordance with good engineering and safety practices for handling flammable, combustible, explosive, or other hazardous materials. Examples of unplanned events which may require a safety device to open include failure of an essential equipment component or a sudden power outage.

Shutdown means for purposes including, but not limited to, periodic maintenance, replacement of equipment, or repair, the cessation of operation of a glycol dehydration unit, or other affected source under this subpart, or equipment required or used solely to comply with this subpart.

Startup means the setting into operation of a glycol dehydration unit, or other affected equipment under this subpart, or equipment required or used to comply with this subpart. Startup includes initial startup and operation solely for the purpose of testing equipment.

Storage vessel means a tank or other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed primarily of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank GOR equal to or greater than 0.31 cubic meters per liter and an API gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Tank battery means a collection of equipment used to separate, treat, store, and transfer crude oil, condensate, natural gas, and produced water. A tank battery typically receives crude oil, condensate, natural gas, or some combination of these extracted products from several production wells for accumulation and separation prior to transmission to a natural gas plant or petroleum refinery. A tank battery may or may not include a glycol dehydration unit.

Temperature monitoring device means an instrument used to monitor temperature and having a minimum accuracy of ±2 percent of the temperature being monitored expressed in °C, or ±2.5 °C, whichever is greater. The temperature monitoring device may

measure temperature in degrees Fahrenheit or degrees Celsius, or both.

Total organic compounds or *TOC*, as used in this subpart, means those compounds which can be measured according to the procedures of Method 18, 40 CFR part 60, appendix A.

Volatile hazardous air pollutant concentration or *VHAP concentration* means the fraction by weight of all HAP contained in a material as determined in accordance with procedures specified in § 63.772(a).

§ 63.762 Startups, shutdowns, and malfunctions.

(a) The provisions set forth in this subpart shall apply at all times except during startups or shutdowns, during malfunctions, and during periods of non-operation of the affected sources (or specific portion thereof) resulting in cessation of the emissions to which this subpart applies. However, during the startup, shutdown, malfunction, or period of non-operation of one portion of an affected source, all emission points which can comply with the specific provisions to which they are subject must do so during the startup, shutdown, malfunction, or period of non-operation.

(b) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the provisions of this subpart during times when emissions are being routed to such items of equipment, if the shutdown would contravene requirements of this subpart applicable to such items of equipment. This paragraph does not apply if the item of equipment is malfunctioning, or if the owner or operator must shut down the equipment to avoid damage due to a contemporaneous startup, shutdown, or malfunction of the affected source or a portion thereof.

(c) During startups, shutdowns, and malfunctions when the requirements of this subpart do not apply pursuant to paragraphs (a) and (b) of this section, the owner or operator shall implement, to the extent reasonably available, measures to prevent or minimize excess emissions to the maximum extent practical. For purposes of this paragraph, the term "excess emissions" means emissions in excess of those that would have occurred if there were no startup, shutdown, or malfunction, and the owner or operator complied with the relevant provisions of this subpart. The measures to be taken shall be identified in the applicable startup, shutdown, and malfunction plan, and may include, but are not limited to, air pollution control technologies, recovery technologies, work practices, pollution prevention, monitoring, and/or changes in the manner of operation of the source. Back-up control devices are not required, but may be used if available.

(d) The owner or operator shall prepare a startup, shutdown, or malfunction plan as required in § 63.6(e)(3) except that the plan is not required to be incorporated by reference into the source's title V permit as specified in § 63.6(e)(3)(i). Instead, the owner or operator shall keep the plan on record as required by § 63.6(e)(3)(v). The failure of the plan to adequately minimize emissions during startup, shutdown, or malfunctions does not shield an owner or operator from enforcement actions.

§ 63.763 [Reserved].

§ 63.764 General standards.

(a) Table 1 of this subpart specifies the provisions of subpart A (General Provisions) that apply and those that do not apply to owners and operators of affected sources subject to this subpart.

(b) All reports required under this subpart shall be sent to the Administrator at the appropriate address listed in § 63.13. Reports may be submitted on electronic media.

(c) Except as specified in paragraph (e) of this section, the owner or operator of an affected source located at an existing or new major source of HAP emissions shall comply with the standards in this subpart as specified in paragraphs (c)(1) through (3) of this section.

(1) For each glycol dehydration unit process vent subject to this subpart, the owner or operator shall comply with the requirements specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) The owner or operator shall comply with the control requirements for glycol dehydration unit process vents specified in § 63.765;

(ii) The owner or operator shall comply with the monitoring requirements specified in § 63.773; and

(iii) The owner or operator shall comply with the recordkeeping and reporting requirements specified in §§ 63.774 and 63.775.

(2) For each storage vessel with the potential for flash emissions subject to this subpart, the owner or operator shall comply with the requirements specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) The control requirements for storage vessels specified in § 63.766;

(ii) The monitoring requirements specified in § 63.773; and

(iii) The recordkeeping and reporting requirements specified in §§ 63.774 and 63.775.

(3) For ancillary equipment (as defined in § 63.761) and compressors at a natural gas processing plant subject to this subpart, the owner or operator shall comply with the requirements for equipment leaks specified in § 63.769.

(d) [Reserved]

(e) *Exemptions.* (1) The owner or operator is exempt from the requirements of paragraph (c)(1) of this section if the criteria listed in paragraph (e)(1)(i) or (e)(1)(ii) are met. Records of the determination of these criteria must be maintained as required in § 63.774(d)(1) of this subpart.

(i) The actual annual average flowrate of natural gas to the glycol dehydration unit is less than 85 thousand standard cubic meters per day, as determined by the procedures specified in § 63.772(b)(1) of this subpart; or

(ii) The actual average emissions of benzene from the glycol dehydration unit process vent to the atmosphere are less than 0.90 megagram per year, as determined by the procedures specified in § 63.772(b)(2) of this subpart.

(2) The owner or operator is exempt from the requirements of paragraph (c)(3) of this section for ancillary equipment (as defined in § 63.761) and compressors at a natural gas processing plant subject to this subpart, if the criteria listed in paragraphs (e)(2)(i) and (e)(2)(ii) are met. Records of the determination of these criteria must be maintained as required in § 63.774(d)(2) of this subpart.

(i) Any ancillary equipment and compressors that contain or contact a fluid (liquid or gas) must have a total VHAP concentration less than 10 percent by weight, as determined by the procedures specified in § 63.772(a) of this subpart; and

(ii) That ancillary equipment and compressors must operate in VHAP service less than 300 hours per calendar year.

(f) Each owner or operator of a major HAP source subject to this subpart is required to apply for a 40 CFR part 70 or part 71 operating permit from the appropriate permitting authority. If the Administrator has approved a State operating permit program under 40 CFR part 70, the permit shall be obtained from the State authority. If a State operating permit program has not been approved, the owner or operator of a source shall apply to the EPA Regional Office pursuant to 40 CFR part 71.

(g) [Reserved]

(h) [Reserved]

(i) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take

action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, a leak is detected and the owner or operator shall take further action as required by the applicable provisions of this subpart.

§ 63.765 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart with an actual annual average natural gas flowrate equal to or greater than 85 thousand standard cubic meters per day and with actual average benzene glycol dehydration unit process vent emissions equal to or greater than 0.90 megagrams per year, that must be controlled for HAP emissions as specified in § 63.764(c)(1)(i).

(b) Except as provided in paragraph (c) of this section, an owner or operator of a glycol dehydration unit process vent shall comply with the requirements specified in paragraphs (b)(1) and (b)(2) of this section.

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i) or (b)(1)(ii) of this section.

(i) The owner or operator shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d).

(ii) The owner or operator shall connect the process vent to a control device or combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be reduced to a level less than 0.90 megagrams per year. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d), except that the performance levels specified in § 63.771(d)(1)(i) and (ii) do not apply.

(2) One or more safety devices that vent directly to the atmosphere may be used on the air emission control equipment installed to comply with paragraph (b)(1) of this section.

(c) As an alternative to the requirements of paragraph (b) of this section, the owner or operator may comply with one of the requirements specified in paragraphs (c)(1) through (3) of this section.

(1) The owner or operator shall control air emissions by connecting the process vent to a process natural gas line.

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the glycol dehydration unit process vent are reduced by 95.0 percent through process modifications, or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.771(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraphs (c)(3)(i) through (c)(3)(ii) of this section, through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) HAP emissions are reduced by 95.0 percent or more.

(ii) Benzene emissions are reduced to a level less than 0.90 megagrams per year.

§ 63.766 Storage vessel standards.

(a) This section applies to each storage vessel with the potential for flash emissions (as defined in § 63.761) subject to this subpart.

(b) The owner or operator of a storage vessel with the potential for flash emissions (as defined in § 63.761) shall comply with one of the control requirements specified in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall equip the affected storage vessel with the potential for flash emissions with a cover that is connected, through a closed-vent system that meets the conditions specified in § 63.771(c), to a control device or a combination of control devices that meets any of the conditions specified in § 63.771(d). The cover shall be designed and operated in accordance with the requirements of § 63.771(b).

(2) The owner or operator of a pressure storage vessel that is designed to operate as a closed system shall operate the storage vessel with no detectable emissions at all times that material is in the storage vessel, except as provided for in paragraph (c) of this section.

(c) One or more safety devices that vent directly to the atmosphere may be used on the storage vessel and air emission control equipment complying with paragraphs (b)(1) and (2) of this section.

(d) This section does not apply to storage vessels for which the owner or operator is meeting the requirements specified in 40 CFR part 60, subpart Kb; or is meeting the requirements specified in 40 CFR part 63, subparts G or CC.

§ 63.767 [Reserved].

§ 63.768 [Reserved].

§ 63.769 Equipment leak standards.

(a) This section applies to equipment subject to this subpart, located at natural gas processing plants and specified in paragraphs (a)(1) and (a)(2) of this section, that contains or contacts a fluid (liquid or gas) that has a total VHAP concentration equal to or greater than 10 percent by weight (determined according to the procedures specified in § 63.772(a)) and that operates in VHAP service equal to or greater than 300 hours per calendar year.

(1) Ancillary equipment, as defined in § 63.761; and

(2) Compressors.

(b) This section does not apply to ancillary equipment and compressors for which the owner or operator is meeting the requirements specified in subpart H of this part; or is meeting the requirements specified in 40 CFR part 60, subpart KKK.

(c) For each piece of ancillary equipment and each compressor subject to this section located at an existing or new source, the owner or operator shall meet the requirements specified in 40 CFR part 61, subpart V, §§ 61.241 through 61.247, except as specified in paragraphs (c)(1) through (8) of this section.

(1) Each pressure relief device in gas/vapor service shall be monitored quarterly and within 5 days after each pressure release to detect leaks, except under the following conditions.

(i) The owner or operator has obtained permission from the Administrator to use an alternative means of emission limitation that achieves a reduction in emissions of VHAP at least equivalent to that achieved by the control required in this subpart.

(ii) The pressure relief device is located in a nonfractionating facility that is monitored only by non-facility personnel, it may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days. Such a pressure relief device shall not be allowed to operate for more than 30 days after a pressure release without monitoring.

(2) For pressure relief devices, if an instrument reading of 10,000 parts per

million or greater is measured, a leak is detected.

(3) For pressure relief devices, when a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, unless a delay in repair of equipment is granted under 40 CFR 61.242-10.

(4) Sampling connection systems are exempt from the requirements of 40 CFR 61.242-5.

(5) Pumps in VHAP service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant that does not have the design capacity to process 283,000 standard cubic meters per day or more of field gas are exempt from the routine monitoring requirements of 40 CFR 61.242-2(a)(1) and 61.242-7(a), and paragraphs (c)(1) through (3) of this section.

(6) Pumps in VHAP service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service located within a natural gas processing plant that is located on the Alaskan North Slope are exempt from the routine monitoring requirements of 40 CFR 61.242-2(a)(1) and 61.242-7(a), and (c)(1) through (3) of this section.

(7) Reciprocating compressors in wet gas service are exempt from the compressor control requirements of 40 CFR 61.242-3.

(8) Flares used to comply with this subpart shall comply with the requirements of § 63.11(b).

§ 63.770 [Reserved].

§ 63.771 Control equipment requirements.

(a) This section applies to each cover, closed-vent system, and control device installed and operated by the owner or operator to control air emissions as required by the provisions of this subpart. Compliance with paragraphs (b), (c), and (d) of this section will be determined by review of the records required by § 63.774 and the reports required by § 63.775, by review of performance test results, and by inspections.

(b) *Cover requirements.* (1) The cover and all openings on the cover (e.g., access hatches, sampling ports, and gauge wells) shall be designed to form a continuous barrier over the entire surface area of the liquid in the tank.

(2) Each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system to a control device designed and operated in accordance with the requirements of paragraphs (c) and (d) of this section.

(c) *Closed-vent system requirements.* (1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in a HAP emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

(2) The closed-vent system shall be designed and operated with no detectable emissions.

(3) If the closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, the owner or operator shall meet the requirements specified in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(i) For each bypass device, except as provided for in paragraph (c)(3)(ii) of this section, the owner or operator shall either:

(A) Properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere that takes a reading at least once every 15 minutes and sounds an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device to the atmosphere; or

(B) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration. The owner or operator shall visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

(d) *Control device requirements.* (1) The control device used to reduce HAP emissions in accordance with the standards of this subpart shall be one of the control devices specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated in accordance with one of the following performance requirements:

(A) Reduces the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.772(e); or

(B) Reduces the concentration of either TOC or total HAP in the exhaust gases at the outlet to the device to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 63.772(e); or

(C) Operates at a minimum residence time of 0.5 seconds at a minimum temperature of 760°C.

(D) If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(ii) A vapor recovery device (e.g., carbon adsorption system or condenser) or other control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.772(e).

(iii) A flare that is designed and operated in accordance with the requirements of § 63.11(b).

(2) [Reserved]

(3) The owner or operator shall demonstrate that a control device achieves the performance requirements of paragraph (d)(1) of this section as specified in § 63.772(e).

(4) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the HAP emissions unit or units through the closed-vent system to the control device, as required under §§ 63.765, 63.766, and 63.769, except when maintenance or repair on a unit cannot be completed without a shutdown of the control device. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.773(d), the owner or operator shall demonstrate compliance according to

the requirements of § 63.772(f) or (g), as applicable.

(5) For each carbon adsorption system used as a control device to meet the requirements of paragraph (d)(1) of this section, the owner or operator shall manage the carbon as follows:

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system.

(ii) The spent carbon removed from the carbon adsorption system shall be either regenerated, reactivated, or burned in one of the units specified in paragraphs (d)(5)(ii)(A) through (d)(5)(ii)(G) of this section.

(A) Regenerated or reactivated in a thermal treatment unit for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(B) Regenerated or reactivated in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(C) Regenerated or reactivated in a thermal treatment unit equipped with and operating organic air emission controls in accordance with a national emissions standard for HAP under another subpart in 40 CFR part 61 or this part.

(D) Burned in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(E) Burned in a hazardous waste incinerator which the owner or operator has designed and operates in accordance with the requirements of 40 CFR part 265, subpart O.

(F) Burned in a boiler or industrial furnace for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(G) Burned in a boiler or industrial furnace which the owner or operator has designed and operates in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(e) *Process modification requirements.* Each owner or operator that chooses to comply with § 63.765(c)(2) shall meet the requirements specified in paragraphs (e)(1) through (e)(3) of this section.

(1) The owner or operator shall determine glycol dehydration unit baseline operations (as defined in § 63.761). Records of glycol dehydration unit baseline operations shall be retained as required under § 63.774(b)(10).

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the percent HAP reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including, but not limited to, changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall HAP emission reduction.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (e)(3)(ii) of this section.

(i) The owner or operator shall maintain records, as required in § 63.774(b)(11), that the facility continues to operate in accordance with the conditions specified under paragraph (e)(2) of this section.

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) of this section, except that the emission reduction achieved shall be the emission reduction specified for the control device(s) in paragraph (e)(2) of this section.

§ 63.772 Test methods, compliance procedures, and compliance demonstrations.

(a) *Determination of material VHAP or HAP concentration to determine the applicability of the equipment leak standards under this subpart (§ 63.769).* Each piece of ancillary equipment and compressors are presumed to be in VHAP service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VHAP service or in wet gas service.

(1) For a piece of ancillary equipment and compressors to be considered not in VHAP service, it must be determined that the percent VHAP content can be reasonably expected never to exceed 10.0 percent by weight. For the purposes of determining the percent VHAP content of the process fluid that is contained in or contacts a piece of ancillary equipment or compressor, Method 18 of 40 CFR part 60, appendix A, shall be used.

(2) For a piece of ancillary equipment and compressors to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction of natural gas liquids.

(b) *Determination of glycol dehydration unit flowrate or benzene emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate or benzene emissions to meet the criteria for an exemption from control requirements under § 63.764(e)(1).

(1) The determination of actual flowrate of natural gas to a glycol dehydration unit shall be made using the procedures of either paragraph (b)(1)(i) or (b)(1)(ii) of this section.

(i) The owner or operator shall install and operate a monitoring instrument that directly measures natural gas flowrate to the glycol dehydration unit with an accuracy of plus or minus 2 percent or better. The owner or operator shall convert annual natural gas flowrate to a daily average by dividing the annual flowrate by the number of days per year the glycol dehydration unit processed natural gas.

(ii) The owner or operator shall document, to the Administrator's satisfaction, that the actual annual average natural gas flowrate to the glycol dehydration unit is less than 85 thousand standard cubic meters per day.

(2) The determination of actual average benzene emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (b)(2)(i) or (b)(2)(ii) of this section. Emissions shall be determined either uncontrolled, or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene emissions using the model GRI-GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI-GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be

determined using the procedures documented in the Gas Research Institute (GRI) report entitled "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene emissions in kilograms per hour through direct measurement by performing three runs of Method 18, 40 CFR Part 60, appendix A (or an equivalent method), and averaging the results of the three runs. Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

(c) *No detectable emissions test procedure.* (1) The no detectable emissions test procedure shall be conducted in accordance with Method 21, 40 CFR part 60, appendix A.

(2) The detection instrument shall meet the performance criteria of Method 21, 40 CFR part 60, appendix A, except that the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) The detection instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21, 40 CFR part 60, appendix A.

(4) Calibration gases shall be as follows:

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air); and

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) An owner or operator may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If an owner or operator chooses to adjust the instrument readings for the background level, the background level value must be determined according to the procedures in Method 21 of 40 CFR part 60, appendix A.

(6)(i) Except as provided in paragraph (c)(6)(i) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the process fluid not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts which are not organic hazardous air pollutants or volatile organic compounds, the average stream response factor shall be calculated on an inert-free basis.

(ii) If no instrument is available at the facility that will meet the performance criteria specified in paragraph (c)(6)(i) of this section, the instrument readings may be adjusted by multiplying by the average response factor of the process fluid, calculated on an inert-free basis as described in paragraph (c)(6)(i) of this section.

(7) An owner or operator must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (c)(7)(i) or (c)(7)(ii) of this section.

(i) If an owner or operator chooses not to adjust the detection instrument readings for the background organic concentration level, then the maximum organic concentration value measured by the detection instrument is compared directly to the applicable value for the potential leak interface as specified in paragraph (c)(8) of this section.

(ii) If an owner or operator chooses to adjust the detection instrument readings for the background organic concentration level, the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (c)(5) of this section is compared with the applicable value for the potential leak interface as specified in paragraph (c)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (c)(7) of this section, is less than 500 parts per million by volume.

(d) [Reserved]

(e) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1) or (e)(3)(ii) using either a performance test as specified in paragraph (e)(3) of this section or a design analysis as specified in paragraph (e)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (e)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent.

(1) The following control devices are exempt from the requirements to conduct performance tests and design analyses under this section:

(i) A flare that is designed and operated in accordance with § 63.11(b);

(ii) A boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) A boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H; or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) A hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O; or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(vi) A control device for which a performance test was conducted for determining compliance with a regulation promulgated by the EPA and the test was conducted using the same methods specified in this section and either no process changes have been made since the test, or the owner or operator can demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process changes.

(2) An owner or operator shall design and operate each flare in accordance with the requirements specified in § 63.11(b) and in paragraphs (e)(2)(i) and (e)(2)(ii) of this section.

(i) The compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(ii) An owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration when a flare is used.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.771(d)(1) or (e)(3)(ii), the owner or operator shall use the test methods and procedures specified in paragraphs (e)(3)(i) through (e)(3)(iv) of this section. The performance test shall be conducted according to the schedule specified in § 63.7(a)(2) and the results of the performance test shall be submitted in the Notification of Compliance Status Report as required in § 63.775(d)(1)(ii.

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites in paragraphs (e)(3)(i)(A) and (B) of this section. Any references to particulate

mentioned in Methods 1 and 1A do not apply to this section.

(A) To determine compliance with the control device percent reduction requirement specified in § 63.771(d)(1)(i)(A), (d)(1)(ii) or (e)(3)(ii), sampling sites shall be located at the inlet of the first control device, and at the outlet of the final control device.

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.771(d)(1)(i)(B), the sampling site shall be located at the outlet of the combustion device.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) To determine compliance with the control device percent reduction performance requirement in § 63.771(d)(1)(i)(A), (d)(1)(ii), and (e)(3)(ii), the owner or operator shall use either Method 18, 40 CFR part 60, appendix A or Method 25A, 40 CFR part 60, appendix A; alternatively, any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A, may be used. The following procedures shall be used to calculate percent reduction efficiency:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of either TOC (minus methane and ethane) or total HAP (E_i, E_o) shall be computed.

(*1*) The following equations shall be used:

$$E_i = K_2\left(\sum_{j=1}^{n} C_{ij} M_{ij}\right) Q_i$$

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj} M_{oj}\right) Q_o$$

Where:

C_{ij}, C_{oj} = Concentration of sample component j of the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

E_i, E_o = Mass rate of TOC (minus methane and ethane) or total HAP at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

M_{ij}, M_{oj} = Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20°C.

(*2*) When the TOC mass rate is calculated, all organic compounds (minus methane and ethane) measured by Method 18, 40 CFR part 60, appendix A, or Method 25A, 40 CFR part 60, appendix A, shall be summed using the equations in paragraph (e)(3)(iii)(B)(*1*) of this section.

(*3*) When the total HAP mass rate is calculated, only HAP chemicals listed in Table 1 of this subpart shall be summed using the equations in paragraph (e)(3)(iii)(B)(*1*) of this section.

(C) The percent reduction in TOC (minus methane and ethane) or total HAP shall be calculated as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} \times 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) or total HAP at the inlet to the control device as calculated under paragraph (e)(3)(iii)(B) of this section, kilograms TOC per hour or kilograms HAP per hour.

E_o = Mass rate of TOC (minus methane and ethane) or total HAP at the outlet of the control device, as calculated under paragraph (e)(3)(iii)(B) of this section, kilograms TOC per hour or kilograms HAP per hour.

(D) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, the weight-percent reduction of total HAP or TOC (minus methane and ethane) across the device shall be determined by comparing the TOC (minus methane and ethane) or total HAP in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) or total HAP exiting the device, respectively.

(iv) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.771(d)(1)(i)(B), the owner or operator shall use either Method 18, 40 CFR part 60, appendix A, or Method 25A, 40 CFR part 60, appendix A, to measure either TOC (minus methane and ethane) or total HAP. Alternatively, any other method or data that have been validated according to Method 301 of appendix A of this part, may be used. The following procedures shall be used to calculate parts per million by volume concentration, corrected to 3 percent oxygen:

(A) The minimum sampling time for each run shall be 1 hour, in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The TOC concentration or total HAP concentration shall be calculated according to paragraph (e)(3)(iv)(B)(*1*) or (e)(3)(iv)(B)(*2*) of this section.

(*1*) The TOC concentration is the sum of the concentrations of the individual components and shall be computed for each run using the following equation:

$$C_{TOC} = \sum_{i=1}^{x} \frac{\left(\sum_{j=1}^{n} C_{ji}\right)}{x}$$

Where:

C_{TOC} = Concentration of total organic compounds minus methane and ethane, dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(*2*) The total HAP concentration shall be computed according to the equation in paragraph (e)(3)(iv)(B)(*1*) of this section, except that only HAP chemicals listed in Table 1 of this subpart shall be summed.

(C) The TOC concentration or total HAP concentration shall be corrected to 3 percent oxygen as follows:

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3B, 40 CFR part 60, appendix A, shall be used to determine the oxygen concentration. The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

(*2*) The TOC or HAP concentration shall be corrected for percent oxygen by using the following equation:

$$C_c = C_m\left(\frac{17.9}{20.9 - \%O_{2d}}\right)$$

Where:

C_c = TOC concentration or total HAP concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_m = TOC concentration or total HAP concentration, dry basis, parts per million by volume.

$\%\ O_{2d}$ = Concentration of oxygen, dry basis, percent by volume.

(4) For a design analysis conducted to meet the requirements of § 63.771(d)(1) or (e)(3)(ii), the owner or operator shall meet the requirements specified in paragraphs (e)(4)(i) and (e)(4)(ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.775(d)(1)(i).

(i) The design analysis shall include analysis of the vent stream characteristics and control device operating parameters for the applicable control device as specified in paragraphs (e)(4)(i)(A) through (F) of this section.

(A) For a thermal vapor incinerator, the design analysis shall include the vent stream composition, constituent concentrations, and flowrate and shall establish the design minimum and average temperatures in the combustion zone and the combustion zone residence time.

(B) For a catalytic vapor incinerator, the design analysis shall include the vent stream composition, constituent concentrations, and flowrate and shall establish the design minimum and average temperatures across the catalyst bed inlet and outlet, and the design service life of the catalyst.

(C) For a boiler or process heater, the design analysis shall include the vent stream composition, constituent concentrations, and flowrate; shall establish the design minimum and average flame zone temperatures and combustion zone residence time; and shall describe the method and location where the vent stream is introduced into the flame zone.

(D) For a condenser, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the design analysis, an owner or operator may elect to use the procedures specified in paragraph (e)(5) of this section.

(E) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(F) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(ii) If the owner or operator and the Administrator do not agree on a demonstration of control device performance using a design analysis then the disagreement shall be resolved using the results of a performance test performed by the owner or operator in accordance with the requirements of paragraph (e)(3) of this section. The Administrator may choose to have an authorized representative observe the performance test.

(5) As an alternative to the procedures in paragraphs (e)(3) and (e)(4)(i)(D) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1) as inputs for the model GRI-GLYCalc™, Version 3.0 or higher, to determine condenser performance.

(f) *Compliance demonstration for control device performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in §§ 63.771(d)(1)(ii) and 63.765(c)(2). Compliance shall be demonstrated using the requirements in paragraphs (f)(1) through (f)(3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.771(d)(1)(ii) or § 63.765(c)(2), may demonstrate compliance according to paragraph (g) of this section. An owner or operator may switch between compliance with paragraph (f) of this section and compliance with paragraph (g) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.775(e), following the change.

(1) The owner or operator shall establish a site specific maximum or minimum monitoring parameter value (as appropriate) according to the requirements of § 63.773(d)(5)(i).

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.773(d)(4).

(3) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (f)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (f)(1) of this section.

(g) *Compliance demonstration with percent reduction performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.771(d)(1)(ii) or § 63.765(c)(2) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (g)(1) through (g)(3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to § 63.773(d)(5)(ii).

(2) Compliance with the percent reduction requirement in § 63.771(d)(1)(ii) or § 63.765(c)(2) shall be demonstrated by the procedures in paragraphs (g)(2)(i) through (g)(2)(iii) of this section.

(i) The owner or operator must calculate the daily average condenser outlet temperature in accordance with § 63.773(d)(4).

(ii) The owner or operator shall determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (g)(2)(i) of this section and the condenser performance curve established under paragraph (g)(1) of this section.

(iii) Except as provided in paragraphs (g)(2)(iii)(A) and (B) of this section, at the end of each operating day, the

owner or operator shall calculate the 365-day average HAP emission reduction from the condenser efficiencies determined in paragraph (g)(2)(ii) of this section for the preceding 365 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.765(c)(2), the 365-day average HAP emission reduction shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency determined in paragraph (g)(2)(ii) of this section, both for the previous 365 operating days.

(A) After the compliance dates specified in § 63.760(f), an owner or operator with less than 120 days of data for determining average HAP emission reduction, shall calculate the average HAP emission reduction for the first 120 days of operation after the compliance dates. Compliance with the performance requirements is achieved if the 120-day average HAP emission reduction is equal to or greater than 90.0 percent.

(B) After 120 days and no more than 364 days of operation after the compliance dates specified in § 63.760(f), the owner or operator shall calculate the average HAP emission reduction as the HAP emission reduction averaged over the number of days between the current day and the applicable compliance date. Compliance with the performance requirements is achieved if the average HAP emission reduction is equal to or greater than 90.0 percent.

(3) If the owner or operator has data for 365 days or more of operation, compliance is achieved with the emission limitation specified in § 63.771(d)(1)(ii) or § 63.765(c)(2) if the average HAP emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than 95.0 percent.

§ 63.773 Inspection and monitoring requirements.

(a) This section applies to an owner or operator using air emission controls in accordance with the requirements of §§ 63.765 and 63.766.

(b) [Reserved]

(c) *Cover and closed-vent system inspection and monitoring requirements.* (1) For each closed-vent system or cover required to comply with this section, the owner or operator shall comply with the requirements of paragraphs (c) (2) through (7) of this section.

(2) Except as provided in paragraphs (c) (5) and (6) of this section, each closed-vent system shall be inspected according to the procedures and schedule specified in paragraphs (c)(2)(i) and (ii) of this section, and each cover shall be inspected according to the procedures and schedule specified in paragraph (c)(2)(iii) of this section.

(i) For each closed-vent system joints, seams, or other connections that are permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), the owner or operator shall:

(A) Conduct an initial inspection according to the procedures specified in § 63.772(c) to demonstrate that the closed-vent system operates with no detectable emissions.

(B) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; or broken or missing caps or other closure devices. The owner or operator shall monitor a component or connection using the procedures in § 63.772(c) to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed.

(ii) For closed-vent system components other than those specified in paragraph (c)(2)(i) of this section, the owner or operator shall:

(A) Conduct an initial inspection according to the procedures specified in § 63.772(c) to demonstrate that the closed-vent system operates with no detectable emissions.

(B) Conduct annual inspections according to the procedures specified in § 63.772(c) to demonstrate that the components or connections operate with no detectable emissions.

(C) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; or broken or missing caps or other closure devices.

(iii) For each cover, the owner or operator shall:

(A) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the tank is buried partially or entirely underground, inspection is required only for those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(B) The inspections shall be conducted initially, following the installation of the cover. Thereafter, the owner or operator shall perform the inspection at least once every calendar year, except as provided in paragraphs (c) (5) and (6) of this section.

(3) In the event that a leak or defect is detected, the owner or operator shall repair the leak or defect as soon as practicable, except as provided in paragraph (c)(4) of this section.

(i) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(ii) Repair shall be completed no later than 15 calendar days after the leak is detected.

(4) Delay of repair of a closed-vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, as defined in § 63.761, 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 shutdown.

(5) Any parts of the closed-vent system or cover that are designated, as described in paragraphs (c)(5) (i) and (ii) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (c)(2)(i), (ii), and (iii) of this section if:

(i) 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 (c)(2)(i), (ii), or (iii) of this section; and

(ii) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(6) Any parts of the closed-vent system or cover that are designated, as described in paragraphs (c)(6) (i) and (ii) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (c)(2)(i), (ii), and (iii) of this section if:

(i) 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

(ii) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years.

(7) Records shall be maintained as specified in § 63.774(b)(5) through (8).

(d) *Control device monitoring requirements.* (1) For each control device, except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (9) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.771(d) or § 63.771(e)(3). The continuous parameter monitoring system shall meet the following specifications and requirements:

(i) Each continuous parameter monitoring system shall measure data values at least once every hour and record either:

(A) Each measured data value; or

(B) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(ii) The monitoring system must be installed, calibrated, operated, and maintained in accordance with the manufacturer's specifications or other written procedures that provide reasonable assurance that the monitoring equipment is operating properly.

(2) An owner or operator is exempt from the monitoring requirements specified in paragraphs (d)(3) through (9) of this section for the following types of control devices:

(i) A boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel; or

(ii) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) The owner or operator shall install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(3)(i), (d)(3)(ii), or (d)(3)(iii) of this section.

(i) A continuous monitoring system that measures the following operating parameters as applicable:

(A) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location in the combustion chamber downstream of the combustion zone.

(B) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations and have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(C) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(D) For a boiler or process heater with a design heat input capacity of less than 44 megawatts, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location in the combustion chamber downstream of the combustion zone.

(E) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location in the exhaust vent stream from the condenser.

(F) For a regenerative-type carbon adsorption system:

(*1*) A continuous parameter monitoring system to measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The integrating regenerating stream flow monitoring device must have an accuracy of ±10 percent; and

(*2*) A continuous parameter monitoring system to measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and to measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater.

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.772(e)(3) or a design analysis in accordance with § 63.772(e)(4)(i)(F) and shall be based on the total carbon working capacity of the control device and source operating schedule.

(ii) A continuous monitoring system that measures the concentration level of organic compounds in the exhaust vent stream from the control device using an organic monitoring device equipped with a continuous recorder. The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B of 40 CFR part 60 and must be installed, calibrated, and maintained according to the manufacturer's specifications.

(iii) A continuous monitoring system that measures alternative operating parameters other than those specified in paragraph (d)(3)(i) or (d)(3)(ii) of this section upon approval of the Administrator as specified in § 63.8(f)(1) through (5).

(4) Using the data recorded by the monitoring system, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the HAP emissions unit operation is continuous, the operating day is a 24-hour period. If HAP emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) For each operating parameter monitor installed in accordance with the requirements of paragraph (d)(3) of this section, the owner or operator shall comply with paragraph (d)(5)(i) of this section for all control devices except for condensers, and when condensers are installed, the owner or operator shall also comply with paragraph (d)(5)(ii) of this section.

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.771(d)(1) or § 63.771(e)(3)(ii). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.772(e)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1) or § 63.771(e)(3)(ii), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by control device design analysis or control device manufacturer recommendations or a combination of both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.772(e)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1) or (e)(3)(ii), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the control device design analysis and may be supplemented by the control device manufacturer's recommendations.

(ii) The owner or operator shall establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency. The curve shall be established as follows:

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.772(e)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.771(d)(1) or (e)(3)(ii), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.772(e)(4)(i)(D) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.771(d)(1) or (e)(3)(ii), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraphs (d)(5)(ii)(A) and (B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1) as inputs for the model GRI-GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(6) An excursion for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (d)(6)(i) through (d)(6)(v) of this section being met. When multiple operating parameters are monitored for the same control device and during the same operating day and more than one of these operating parameters meets an excursion criterion specified in paragraphs (d)(6)(i) through (d)(6)(v) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(i) An excursion occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established for the operating parameter in accordance with the requirements of paragraph (d)(5)(i) of this section.

(ii) An excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent.

(iii) If an owner or operator has less than 365 days of data, an excursion occurs when the average condenser efficiency calculated according to the procedures specified in § 63.772(g)(2)(iii)(A) or (B) is less than 90.0 percent.

(iv) An excursion occurs when the monitoring data are not available for at least 75 percent of the operating hours.

(v) If the closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, an excursion occurs when:

(A) For each bypass line subject to § 63.771(c)(3)(i)(A) the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(B) For each bypass line subject to § 63.771(c)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(7) For each excursion, except as provided for in paragraph (d)(8) of this section, the owner or operator shall be deemed to have failed to have applied control in a manner that achieves the required operating parameter limits. Failure to achieve the required operating parameter limits is a violation of this standard.

(8) An excursion is not a violation of the operating parameter limit as specified in paragraphs (d)(8)(i) and (d)(8)(ii) of this section.

(i) An excursion does not count toward the number of excused excursions allowed under paragraph (d)(8)(ii) of this section when the excursion occurs during any one of the following periods:

(A) During a period of startup, shutdown, or malfunction when the affected facility is operated during such period in accordance with the facility's startup, shutdown, and malfunction plan; or

(B) During periods of non-operation of the unit or the process that is vented to the control device (resulting in cessation of HAP emissions to which the monitoring applies).

(ii) For each control device, or combinations of control devices installed on the same HAP emissions unit, one excused excursion is allowed per semiannual period for any reason. The initial semiannual period is the 6-month reporting period addressed by the first Periodic Report submitted by the owner or operator in accordance with § 63.775(e) of this subpart.

(9) Nothing in paragraphs (d)(1) through (d)(8) of this section shall be construed to allow or excuse a monitoring parameter excursion caused by any activity that violates other applicable provisions of this subpart.

§ 63.774 Recordkeeping requirements.

(a) The recordkeeping provisions of 40 CFR part 63, subpart A, that apply and those that do not apply to owners and operators of sources subject to this subpart are listed in Table 2 of this subpart.

(b) Except as specified in paragraphs (c) and (d) of this section, each owner or operator of a facility subject to this subpart shall maintain the records specified in paragraphs (b)(1) through (b)(11) of this section:

(1) The owner or operator of an affected source subject to the provisions of this subpart shall maintain files of all information (including all reports and notifications) required by this subpart. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report or period.

(i) All applicable records shall be maintained in such a manner that they can be readily accessed.

(ii) The most recent 12 months of records shall be retained on site or shall be accessible from a central location by

computer or other means that provides access within 2 hours after a request.

(iii) The remaining 4 years of records may be retained offsite.

(iv) Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

(2) Records specified in § 63.10(b)(2);

(3) Records specified in § 63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of § 63.773(d). Notwithstanding the requirements of § 63.10(c), monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (b)(3)(iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating.

(i) Monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments;

(ii) Startups, shutdowns, or malfunctions events. During startups, shutdowns, or malfunction events, the owner or operator shall maintain records indicating whether or not the startup, shutdown or malfunction plan required under § 63.762(d), was followed.

(iii) Periods of non-operation resulting in cessation of the emissions to which the monitoring applies; and

(iv) Excursions due to invalid data as defined in § 63.773(d)(6)(iv).

(4) Each owner or operator using a control device to comply with § 63.764 of this subpart shall keep the following records up-to-date and readily accessible:

(i) Continuous records of the equipment operating parameters specified to be monitored under § 63.773(d) of this subpart or specified by the Administrator in accordance with § 63.773(d)(3)(iii) of this subpart. For flares, the hourly records and records of pilot flame outages specified in § 63.773(d)(3)(i)(C) of this subpart shall be maintained in place of continuous records.

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.773(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) and (B) of this section.

(A) For flares, records of the times and duration of all periods during which all pilot flames are absent shall be kept rather than daily averages.

(B) For condensers installed to comply with § 63.765, records of the annual 365-day rolling average condenser efficiency determined under § 63.772(g) shall be kept in addition to the daily averages.

(iii) Hourly records of whether the flow indicator specified under § 63.771(c)(3)(i)(A) was operating and whether flow was detected at any time during the hour, as well as records of the times and durations of all periods when the vent stream is diverted from the control device or the monitor is not operating.

(iv) Where a seal or closure mechanism is used to comply with § 63.771(c)(3)(i)(B), hourly records of flow are not required. In such cases, the owner or operator shall record that the monthly visual inspection of the seals or closure mechanism has been done, and shall record the duration of all periods when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out, and records of any car-seal that has broken.

(5) Records identifying all parts of the cover or closed-vent system that are designated as unsafe to inspect in accordance with § 63.773(c)(5), an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(6) Records identifying all parts of the cover or closed-vent system that are designated as difficult to inspect in accordance with § 63.773(c)(6), an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(7) For each inspection conducted in accordance with § 63.773(c), during which a leak or defect is detected, a record of the information specified in paragraphs (b)(7)(i) through (b)(7)(viii) of this section.

(i) The instrument identification numbers, operator name or initials, and identification of the equipment.

(ii) The date the leak or defect was detected and the date of the first attempt to repair the leak or defect.

(iii) Maximum instrument reading measured by the method specified in § 63.772(c) after the leak or defect is successfully repaired or determined to be nonrepairable.

(iv) "Repair delayed" and the reason for the delay if a leak or defect is not repaired within 15 calendar days after discovery of the leak or defect.

(v) The name, initials, or other form of identification of the owner or operator (or designee) whose decision it was that repair could not be effected without a shutdown.

(vi) The expected date of successful repair of the leak or defect if a leak or defect is not repaired within 15 calendar days.

(vii) Dates of shutdowns that occur while the equipment is unrepaired.

(viii) The date of successful repair of the leak or defect.

(8) For each inspection conducted in accordance with § 63.773(c) during which no leaks or defects are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(9) Records identifying ancillary equipment and compressors that are subject to and controlled under the provisions of 40 CFR part 60, subpart KKK; 40 CFR part 61, subpart V; or 40 CFR part 63, subpart H.

(10) Records of glycol dehydration unit baseline operations calculated as required under § 63.771(e)(1).

(11) Records required in § 63.771(e)(3)(i) documenting that the facility continues to operate under the conditions specified in § 63.771(e)(2).

(c) An owner or operator that elects to comply with the benzene emission limit specified in § 63.765(b)(1)(ii) shall document, to the Administrator's satisfaction, the following items:

(1) The method used for achieving compliance and the basis for using this compliance method; and

(2) The method used for demonstrating compliance with 0.90 megagrams per year of benzene.

(3) Any information necessary to demonstrate compliance as required in the methods specified in paragraphs (c)(1) and (c)(2) of this section.

(d) (1) An owner or operator that is exempt from control requirements under § 63.764(e)(1) shall maintain the records specified in paragraph (d)(1)(i) or (d)(1)(ii) of this section, as appropriate, for each glycol dehydration unit that is not controlled according to the requirements of § 63.764(c)(1)(i).

(i) The actual annual average natural gas throughput (in terms of natural gas flowrate to the glycol dehydration unit per day) as determined in accordance with § 63.772(b)(1), or

(ii) The actual average benzene emissions (in terms of benzene emissions per year) as determined in accordance with § 63.772(b)(2).

(2) An owner or operator that is exempt from the control requirements under § 63.764(e)(2) of this subpart shall maintain the following records:

(i) Information and data used to demonstrate that a piece of equipment is not in VHAP service or not in wet gas service shall be recorded in a log that is kept in a readily accessible location.

(ii) Identification and location of equipment, located at a natural gas processing plant subject to this subpart, that is in VHAP service less than 300 hours per year.

(e) Record the following when using a flare to comply with § 63.771(d):

(1) Flare design (i.e., steam-assisted, air-assisted, or non-assisted);

(2) All visible emission readings, heat content determinations, flowrate measurements, and exit velocity determinations made during the compliance determination required by § 63.772(e)(2); and

(3) All periods during the compliance determination when the pilot flame is absent.

§ 63.775 Reporting requirements.

(a) The reporting provisions of subpart A of this part, that apply and those that do not apply to owners and operators of sources subject to this subpart are listed in Table 2 of this subpart.

(b) Each owner or operator of a major source subject to this subpart shall submit the information listed in paragraphs (b)(1) through (b)(6) of this section, except as provided in paragraphs (b)(7) and (b)(8) of this section.

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000 and plan to be area sources by June 17, 2002 shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(2) The date of the performance evaluation as specified in § 63.8(e)(2), required only if the owner or operator is required by the Administrator to conduct a performance evaluation for a continuous monitoring system. A separate notification of the performance evaluation is not required if it is included in the initial notification submitted in accordance with paragraph (b)(1) of this section.

(3) The planned date of a performance test at least 60 days before the test in accordance with § 63.7(b). Unless requested by the Administrator, a site-specific test plan is not required by this subpart. If requested by the Administrator, the owner or operator must also submit the site-specific test plan required by § 63.7(c) with the notification of the performance test. A separate notification of the performance test is not required if it is included in the initial notification submitted in accordance with paragraph (b)(1) of this section.

(4) A Notification of Compliance Status report as described in paragraph (d) of this section;

(5) Periodic Reports as described in paragraph (e) of this section; and

(6) Startup, shutdown, and malfunction reports specified in § 63.10(d)(5) shall be submitted as required. Separate startup, shutdown, and malfunction reports as described in § 63.10(d)(5) are not required if the information is included in the Periodic Report specified in paragraph (e) of this section.

(7) Each owner or operator of a glycol dehydration unit subject to this subpart that is exempt from the control requirements for glycol dehydration unit process vents in § 63.765, is exempt from all reporting requirements for major sources in this subpart, for that unit.

(8) Each owner or operator of ancillary equipment and compressors subject to this subpart that are exempt from the control requirements for equipment leaks in § 63.769, are exempt from all reporting requirements for major sources in this subpart, for that equipment.

(c) [Reserved]

(d) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status Report as required under § 63.9(h) within 180 days after the compliance date specified in § 63.760(f). In addition to the information required under § 63.9(h), the Notification of Compliance Status Report shall include the information specified in paragraphs (d)(1) through (d)(11) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If all of the information required under this paragraph has been submitted at any time prior to 180 days after the applicable compliance dates specified in § 63.760(f), a separate Notification of Compliance Status Report is not required. If an owner or operator submits the information specified in paragraphs (d)(1) through (d)(11) of this section at different times, and/or different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information.

(1) If a closed-vent system and a control device other than a flare are used to comply with § 63.764, the owner or operator shall submit:

(i) The design analysis documentation specified in § 63.772(e)(4) of this subpart, if the owner or operator elects to prepare a design analysis; or

(ii) If the owner or operator elects to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.772(e)(3) and that the test conditions are representative of current operating conditions.

(A) The percent reduction of HAP or TOC, or the outlet concentration of HAP or TOC (parts per million by volume on a dry basis), determined as specified in § 63.772(e)(3) of this subpart; and

(B) The value of the monitored parameters specified in § 63.773(d) of this subpart, or a site-specific parameter approved by the permitting agency, averaged over the full period of the performance test.

(2) If a closed-vent system and a flare are used to comply with § 63.764, the owner or operator shall submit performance test results including the information in paragraphs (d)(2) (i) and (ii) of this section.

(i) All visible emission readings, heat content determinations, flowrate measurements, and exit velocity determinations made during the compliance determination required by § 63.772(e)(2) of this subpart, and

(ii) A statement of whether a flame was present at the pilot light over the full period of the compliance determination.

(3) For each owner or operator subject to the provisions specified in § 63.769, the owner or operator shall submit the information required by § 61.247(a), except that the initial report required in § 61.247(a) shall be submitted as a part of the Notification of Compliance Status Report required in paragraph (d) of this section. The owner or operator shall also submit the information specified in paragraphs (d)(3) (i) and (ii) of this section.

(i) The number of each equipment (e.g., valves, pumps, etc.) excluding equipment in vacuum service, and

(ii) Any change in the information submitted in this paragraph shall be provided to the Administrator as a part of subsequent Periodic Reports described in paragraph (e)(2)(iv) of this section.

(4) The owner or operator shall submit one complete test report for each test method used for a particular source.

(i) For additional tests performed using the same test method, the results

specified in paragraph (d)(1)(ii) of this section shall be submitted, but a complete test report is not required.

(ii) A complete test report shall include a sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method.

(5) For each control device other than a flare used to meet the requirements of § 63.764, the owner or operator shall submit the information specified in paragraphs (d)(5) (i) through (iii) of this section for each operating parameter required to be monitored in accordance with the requirements of § 63.773(d).

(i) The minimum operating parameter value or maximum operating parameter value, as appropriate for the control device, established by the owner or operator to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.771(d)(1) or (e)(3)(ii).

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.773(d)(5). This explanation shall include any data and calculations used to develop the value and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.771(d)(1) or § 63.771(e)(3)(ii).

(iii) A definition of the source's operating day for purposes of determining daily average values of monitored parameters. The definition shall specify the times at which an operating day begins and ends.

(6) Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status Report.

(7) After a title V permit has been issued to the owner or operator of an affected source, the owner or operator of such source shall comply with all requirements for compliance status reports contained in the source's title V permit, including reports required under this subpart. After a title V permit has been issued to the owner or operator of an affected source, and each time a notification of compliance status is required under this subpart, the owner or operator of such source shall submit the notification of compliance status to the appropriate permitting authority following completion of the relevant compliance demonstration activity specified in this subpart.

(8) The owner or operator that elects to comply with the requirements of § 63.765(b)(1)(ii) shall submit the records required under § 63.774(c).

(9) The owner or operator shall submit an analysis demonstrating whether an affected source is a major source using the maximum throughput calculated according to § 63.760(a)(1).

(10) The owner or operator shall submit a statement as to whether the source has complied with the requirements of this subpart.

(11) The owner or operator shall submit the analysis prepared under § 63.771(e)(2) to demonstrate the conditions by which the facility will be operated to achieve an overall HAP emission reduction of 95.0 percent through process modifications or a combination of process modifications and one or more control devices.

(e) *Periodic Reports.* An owner or operator shall prepare Periodic Reports in accordance with paragraphs (e) (1) and (2) of this section and submit them to the Administrator.

(1) An owner or operator shall submit Periodic Reports semiannually, beginning 60 operating days after the end of the applicable reporting period. The first report shall be submitted no later than 240 days after the date the Notification of Compliance Status Report is due and shall cover the 6-month period beginning on the date the Notification of Compliance Status Report is due.

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (ix) of this section, as applicable.

(i) The information required under § 63.10(e)(3). For the purposes of this subpart and the information required under § 63.10(e)(3), excursions (as defined in § 63.773(d)(6)) shall be considered excess emissions.

(ii) A description of all excursions as defined in § 63.773(d)(6) of this subpart that have occurred during the 6-month reporting period.

(A) For each excursion caused when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit), as specified in § 63.773(d)(6)(i), the report must include the daily average values of the monitored parameter, the applicable operating parameter limit, and the date and duration of the period that the excursion occurred.

(B) For each excursion caused when the 365-day average condenser control efficiency is less than 95.0 percent, as specified in § 63.773(d)(6)(ii), the report must include the 365-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

(C) For each excursion caused when condenser control efficiency is less than 90.0 percent, as calculated according to the procedures specified in § 63.772(g)(2)(iii) (A) or (B), the report must include the average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

(D) For each excursion caused by lack of monitoring data, as specified in § 63.773(d)(6)(iii), the report must include the date and duration of the period when the monitoring data were not collected and the reason why the data were not collected.

(iii) For each inspection conducted in accordance with § 63.773(c) during which a leak or defect is detected, the records specified in § 63.774(b)(7) must be included in the next Periodic Report.

(iv) For each owner or operator subject to the provisions specified in § 63.769, the owner or operator shall comply with the reporting requirements specified in 40 CFR 61.247, except that the Periodic Reports shall be submitted on the schedule specified in paragraph (e)(1) of this section.

(v) For each closed-vent system with a bypass line subject to § 63.771(c)(3)(i)(A), records required under § 63.774(b)(4)(iii) of all periods when the vent stream is diverted from the control device through a bypass line. For each closed-vent system with a bypass line subject to § 63.771(c)(3)(i)(B), records required under § 63.774(b)(4)(iv) of all periods in which the seal mechanism is broken, the bypass valve position has changed, or the key to unlock the bypass line valve was checked out.

(vi) If an owner or operator elects to comply with § 63.765(b)(1)(ii), the records required under § 63.774(c)(3).

(vii) The information in paragraphs (e)(2)(vii) (A) and (B) of this section shall be stated in the Periodic Report, when applicable.

(A) No excursions.

(B) No continuous monitoring system has been inoperative, out of control, repaired, or adjusted.

(viii) Any change in compliance methods as specified in § 63.772(f).

(ix) If the owner or operator elects to comply with § 63.765(c)(2), the records required under § 63.774(b)(11).

(f) *Notification of process change.* Whenever a process change is made, or

a change in any of the information submitted in the Notification of Compliance Status Report, the owner or operator shall submit a report within 180 days after the process change is made or as a part of the next Periodic Report as required under paragraph (e) of this section, whichever is sooner. The report shall include:

(1) A brief description of the process change;

(2) A description of any modification to standard procedures or quality assurance procedures;

(3) Revisions to any of the information reported in the original Notification of Compliance Status Report under paragraph (d) of this section; and

(4) Information required by the Notification of Compliance Status Report under paragraph (d) of this section for changes involving the addition of processes or equipment.

§ 63.776 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(l) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities will not be delegated to States for §§ 63.772 and 63.777 of this subpart.

§ 63.777 Alternative means of emission limitation.

(a) If, in the judgment of the Administrator, an alternative means of emission limitation will achieve a reduction in HAP emissions at least equivalent to the reduction in HAP emissions from that source achieved under the applicable requirements in §§ 63.764 through 63.771, the Administrator will publish in the **Federal Register** a notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section shall be published only after public notice and an opportunity for a hearing.

(c) Any person seeking permission to use an alternative means of compliance under this section shall collect, verify, and submit to the Administrator information demonstrating that the alternative achieves equivalent emission reductions.

§ 63.778 [Reserved]

§ 63.779 [Reserved]

Appendix to Subpart HH—Tables

TABLE 1 TO SUBPART HH.—LIST OF HAZARDOUS AIR POLLUTANTS FOR SUBPART HH

CAS Number[a]	Chemical name
75070 ...	Acetaldehyde
71432 ...	Benzene (includes benzene in gasoline)
75150 ...	Carbon disulfide
463581	Carbonyl sulfide
100414	Ethyl benzene
107211	Ethylene glycol
50000 ...	Formaldehyde
110543	n-Hexane
91203 ...	Naphthalene
108883	Toluene
540841	2,2,4-Trimethylpentane
1330207	Xylenes (isomers and mixture)
95476 ...	o-Xylene
108383	m-Xylene
106423	p-Xylene

[a] CAS numbers refer to the Chemical Abstracts Services registry number assigned to specific compounds, isomers, or mixtures of compounds.

TABLE 2 TO SUBPART HH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH

General provisions reference	Applicable to subpart HH	Explanation
§ 63.1(a)(1)	Yes	
§ 63.1(a)(2)	Yes	
§ 63.1(a)(3)	Yes	
§ 63.1(a)(4)	Yes	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6) through (a)(8)	Yes	
§ 63.1(a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes	
§ 63.1(a)(11)	Yes	
§ 63.1(a)(12) through (a)(14)	Yes	
§ 63.1(b)(1)	No	Subpart HH specifies applicability.
§ 63.1(b)(2)	Yes	
§ 63.1(b)(3)	No	
§ 63.1(c)(1)	No	Subpart HH specifies applicability.
§ 63.1(c)(2)	No	
§ 63.1(c)(3)	No	Section reserved.
§ 63.1(c)(4)	Yes	
§ 63.1(c)(5)	Yes	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HH.
§ 63.3(a) through (c)	Yes	
§ 63.4(a)(1) through (a)(3)	Yes	
§ 63.4(a)(4)	No	Section reserved.
§ 63.4(a)(5)	Yes	
§ 63.4(b)	Yes	
§ 63.4(c)	Yes	
§ 63.5(a)(1)	Yes	
§ 63.5(a)(2)	No	Preconstruction review required only for major sources that commence construction after promulgation of the standard.
§ 63.5(b)(1)	Yes	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes	

TABLE 2 TO SUBPART HH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.5(b)(4)	Yes	
§ 63.5(b)(5)	Yes	
§ 63.5(b)(6)	Yes	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes	
§ 63.5(d)(2)	Yes	
§ 63.5(d)(3)	Yes	
§ 63.5(d)(4)	Yes	
§ 63.5(e)	Yes	
§ 63.5(f)(1)	Yes	
§ 63.5(f)(2)	Yes	
§ 63.6(a)	Yes	
§ 63.6(b)(1)	Yes	
§ 63.6(b)(2)	Yes	
§ 63.6(b)(3)	Yes	
§ 63.6(b)(4)	Yes	
§ 63.6(b)(5)	Yes	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes	
§ 63.6(c)(1)	Yes	
§ 63.6(c)(2)	Yes	
§ 63.6(c)(3) through (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)	Yes	Except as otherwise specified.
§ 63.6(e)(1)(i)	No	Addressed in § 63.762.
§ 63.6(e)(1)(ii)	Yes	
§ 63.6(e)(1)(iii)	Yes	
§ 63.6(e)(2)	Yes	
§ 63.6(e)(3)(i)	Yes	Except as otherwise specified.
§ 63.6(e)(3)(i)(A)	No	Addressed by § 63.762(c).
§ 63.6(e)(3)(i)(B)	Yes	
§ 63.6(e)(3)(i)(C)	Yes	
§ 63.6(e)(3)(ii) through (3)(vi)	Yes	
§ 63.6(e)(3)(vii).		
§ 63.6(e)(3)(vii)(A)	Yes	
§ 63.6(e)(3)(vii)(B)	Yes	Except that the plan must provide for operation in compliance with § 63.762(c).
§ 63.6(e)(3)(vii)(C)	Yes	
§ 63.6(e)3)(viii)	Yes	
§ 63.6(f)(1)	Yes	
§ 63.6(f)(2)	Yes	
§ 63.6(f)(3)	Yes	
§ 63.6(g)	Yes	
§ 63.6(h)	No	Subpart HH does not require continuous emissions monitoring systems.
§ 63.6(i)(1) through (i)(14)	Yes	
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes	
§ 63.6(j)	Yes	
§ 63.7(a)(1)	Yes	
§ 63.7(a)(2)	Yes	
§ 63.7(a)(3)	Yes	
§ 63.7(b)	Yes	
§ 63.7(c)	Yes	
§ 63.7(d)	Yes	
§ 63.7(e)(1)	Yes	
§ 63.7(e)(2)	Yes	
§ 63.7(e)(3)	Yes	
§ 63.7(e)(4)	Yes	
§ 63.7(f)	Yes	
§ 63.7(g)	Yes	
§ 63.7(h)	Yes	
§ 63.8(a)(1)	Yes	
§ 63.8(a)(2)	No	Section reserved.
§ 63.8(a)(3)	Yes	
§ 63.8(a)(4)	Yes	
§ 63.8(b)(1)	Yes	
§ 63.8(b)(2)	Yes	
§ 63.8(b)(3)	Yes	
§ 63.8(c)(1)	Yes	
§ 63.8(c)(2)	Yes	
§ 63.8(c)(3)	Yes	

TABLE 2 TO SUBPART HH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.8(c)(4)	No	
§ 63.8(c)(5) through (c)(8)	Yes	
§ 63.8(d)	Yes	
§ 63.8(e)	Yes	Subpart HH does not specifically require continuous emissions monitor performance evaluations, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes	
§ 63.8(f)(6)	No	Subpart HH does not require continuous emissions monitoring.
§ 63.8(g)	No	Subpart HH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes	
§ 63.9(b)(1)	Yes	
§ 63.9(b)(2)	Yes	Sources are given 1 year (rather than 120 days) to submit this notification.
§ 63.9(b)(3)	Yes	
§ 63.9(b)(4)	Yes	
§ 63.9(b)(5)	Yes	
§ 63.9(c)	Yes	
§ 63.9(d)	Yes	
§ 63.9(e)	Yes	
§ 63.9(f)	Yes	
§ 63.9(g)	Yes	
§ 63.9(h)(1) through (h)(3)	Yes	
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) through (h)(6)	Yes	
§ 63.9(i)	Yes	
§ 63.9(j)	Yes	
§ 63.10(a)	Yes	
§ 63.10(b)(1)	Yes	
§ 63.10(b)(2)	Yes	
§ 63.10(b)(3)	No	
§ 63.10(c)(1)	Yes	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) Through (c)(8)	Yes	
§ 63.10(c)(9)	No	Section reserved.
§ 63.10(c)(10) through (c)(15)	Yes	
§ 63.10(d)(1)	Yes	
§ 63.10(d)(2)	Yes	
§ 63.10(d)(3)	Yes	
§ 63.10(d)(4)	Yes	
§ 63.10(d)(5)	Yes	Subpart HH requires major sources to submit a startup, shutdown and malfunction report semi-annually.
§ 63.10(e)(1)	Yes	
§ 63.10(e)(2)	Yes	
§ 63.10(e)(3)(i)	Yes	Subpart HH requires major sources to submit Periodic Reports semi-annually.
§ 63.10(e)(3)(i)(A)	Yes	
§ 63.10(e)(3)(i)(B)	Yes	
§ 63.10(e)(3)(i)(C)	No	Subpart HH does not require quarterly reporting for excess emissions.
§ 63.10(e)(3)(ii) through (viii)	Yes	
§ 63.10(f)	Yes	
§ 63.11(a) and (b)	Yes	
§ 63.12(a) through (c)	Yes	
§ 63.13(a) through (c)	Yes	
§ 63.14(a) and (b)	Yes	
§ 63.15(a) and (b)	Yes	

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

3. Part 63 is amended by adding subpart HHH to read as follows:

Subpart HHH—National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities

Sec.

63.1270 Applicability and designation of affected source.
63.1271 Definitions.
63.1272 Startups, shutdowns, and malfunctions.
63.1273 [Reserved]
63.1274 General standards.
63.1275 Glycol dehydration unit process vent standards.
63.1276-63.1280 [Reserved]
63.1281 Control equipment requirements.
63.1282 Test methods, compliance procedures, and compliance demonstrations.
63.1283 Inspection and monitoring requirements.
63.1284 Recordkeeping requirements.
63.1285 Reporting requirements.
63.1286 Delegation of authority.
63.1287 Alternative means of emission limitation.

63.1288 [Reserved]
63.1289 [Reserved]
Appendix to Subpart HHH—Tables

Subpart HHH—National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities

§ 63.1270 Applicability and designation of affected source.

(a) This subpart applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants (HAP) emissions as determined using the maximum natural gas throughput calculated in either paragraph (a)(1) or (a)(2) of this section and paragraphs (a)(3) and (a)(4) of this section. A compressor station that transports natural gas prior to the point of custody transfer, or to a natural gas processing plant (if present) is considered a part of the oil and natural gas production source category. A facility that is determined to be an area source, based on emission estimates using the maximum natural gas throughput calculated as specified in paragraph (a)(1) or (a)(2) of this section, but subsequently increases emissions or potential to emit above the major source levels (without first obtaining and complying with other limitations that keep its potential to emit HAP below major source levels, becomes a major source and must comply thereafter with all applicable provisions of this subpart starting on the applicable compliance date specified in paragraph (d) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

(1) Facilities that store natural gas or facilities that transport and store natural gas shall determine major source status using the maximum annual facility natural gas throughput calculated according to paragraphs (a)(1)(i) through (a)(1)(iv) of this section.

(i) The owner or operator shall determine the number of hours to complete the storage cycle for the facility. The storage cycle is the number of hours for the injection cycle, calculated according to the equation in paragraph (a)(1)(i)(A) of this section, plus the number of hours for the withdrawal cycle, calculated according to the equation in paragraph (a)(1)(i)(B) of this section.

(A) The hours for the facility injection cycle are determined according to the following equation:

$$IC = \frac{WGC}{IR_{max}}$$

Where:

IC = Facility injection cycle in hours/cycle.

WGC = Working gas capacity in cubic meters. The working gas capacity is defined as the maximum storage capacity minus the FERC cushion (as defined in § 63.1271).

IR_{max} = Maximum facility injection rate in cubic meters per hour.

(B) The hours for the facility withdrawal cycle are determined according to the following equation:

$$WC = \frac{WGC}{WR_{max}}$$

Where:

WC = Facility withdrawal cycle, hours/cycle.

WGC = Working gas capacity, cubic meters. The working gas capacity is defined as the maximum storage capacity minus the FERC cushion (as defined in § 63.1271) and shall be the same value as used in paragraph (a)(1)(i)(A) of this section.

WR_{max} = Maximum facility withdrawal rate in cubic meters per hour.

(ii) The owner or operator shall calculate the number of storage cycles for the facility per year according to the following equation:

$$Cycle = \frac{8760\ hr/yr}{IC + WC}$$

Where:

Cycle = Number of storage cycles for the facility per year.

IC = Number of hours for a facility injection cycle, hours/cycle, as calculated in paragraph (a)(1)(i)(A) of this section.

WC = Number of hours for a facility withdrawal cycle, hours/cycle, as calculated in paragraph (a)(1)(i)(B) of this section.

(iii) The owner or operator shall calculate the facilitywide maximum annual glycol dehydration unit hours of operation based on the following equation:

Operation = Cycles × WC

Where:

Operation = Facilitywide maximum annual glycol dehydration unit hours of operation (hr/yr).

Cycles = Number of storage cycles for the facility per year, as calculated in paragraph (a)(1)(ii) of this section.

WC = Number of hours for a facility withdrawal cycle, hours/cycle, as calculated in paragraph (a)(1)(i)(B) of this section.

(iv) The owner or operator shall calculate the maximum facilitywide natural gas throughput based on the following equation:

Throughput = Operation × WR_{max}

Where:

Throughput = Maximum facilitywide natural gas throughput in cubic meters per year.

Operation = Maximum facilitywide annual glycol dehydration unit hours of operation in hours per year, as calculated in paragraph (a)(1)(iii) of this section.

WR_{max} = Maximum facility withdrawal rate in cubic meters per hour.

(2) Facilities that only transport natural gas shall calculate the maximum natural gas throughput as the highest annual natural gas throughput over the 5 years prior to June 17, 1999, multiplied by a factor of 1.2.

(3) The owner or operator shall maintain records of the annual facility natural gas throughput each year and upon request, submit such records to the Administrator. If the facility annual natural gas throughput increases above the maximum natural gas throughput calculated in paragraph (a)(1) or (a)(2) of this section, the maximum natural gas throughput must be recalculated using the higher throughput multiplied by a factor of 1.2.

(4) The owner or operator shall determine the maximum values for other parameters used to calculate potential emissions as the maximum over the same period for which maximum throughput is determined as specified in paragraph (a)(1) or (a)(2) of this section. These parameters shall be based on an annual average or the highest single measured value.

(b) The affected source is each glycol dehydration unit.

(c) The owner or operator of a facility that does not contain an affected source, as specified in paragraph (b) of this section, is not subject to the requirements of this subpart.

(d) The owner or operator of each affected source shall achieve compliance with the provisions of this subpart by the following dates:

(1) The owner or operator of an affected source, the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with this provisions of the subpart no later than June 17, 2002 except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) The owner or operator of an affected source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

(e) An owner or operator of an affected source that is a major source or is located at a major source and is subject to the provisions of this subpart is also subject to 40 CFR part 70 or part 71 permitting requirements.

(f) *Exemptions.* A facility with a facilitywide actual annual average natural gas throughput less than 28.3 thousand standard cubic meters per day, where glycol dehydration units are the only HAP emission source, is not subject to the requirements of this subpart. Records shall be maintained as required in § 63.10(b)(3).

§ 63.1271 Definitions.

All terms used in this subpart shall have the meaning given to them in the Clean Air Act, subpart A of this part (General Provisions), and in this section. If the same term is defined in subpart A and in this section, it shall have the meaning given in this section for purposes of this subpart.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting thermal energy in the form of steam or hot water. Boiler also means any industrial furnace as defined in 40 CFR 260.10.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system shall not be considered a closed-vent system and is not subject to closed-vent system standards.

Combustion device means an individual unit of equipment, such as a flare, incinerator, process heater, or boiler, used for the combustion of organic HAP emissions.

Compressor station means any permanent combination of compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

Continuous recorder means a data recording device that either records an instantaneous data value at least once every hour or records hourly or more frequent block average values.

Control device means any equipment used for recovering or oxidizing HAP or volatile organic compounds (VOC) vapors. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (i.e., injected into the flame zone of a combustion device), returned back to the process, or sold, then the recovery system used, including piping, connections, and flow inducing devices, is not considered to be control devices or closed-vent systems.

Custody transfer means the transfer of hydrocarbon liquids or natural gas:

(1) After processing and/or treatment in the producing operations; or

(2) From storage vessels or automatic transfer facilities, or other equipment, including product loading racks, to pipelines or any other forms of transportation.

Facility means any grouping of equipment where natural gas is processed, compressed, or stored prior to entering a pipeline to a local distribution company or (if there is no local distribution company) to a final end user. Examples of a facility for this source category are: an underground natural gas storage operation; or a natural gas compressor station that receives natural gas via pipeline, from an underground natural gas storage operation, or from a natural gas processing plant. The emission points associated with these phases include, but are not limited to, process vents. Processes that may have vents include, but are not limited to, dehydration and compressor station engines.

Facility, for the purpose of a major source determination, means natural gas transmission and storage equipment that is located inside the boundaries of an individual surface site (as defined in this section) and is connected by ancillary equipment, such as gas flow lines or power lines. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Natural gas transmission and storage equipment or groupings of equipment located on different gas leases, mineral fee tracts, lease tracts, subsurface unit areas, surface fee tracts, or surface lease tracts shall not be considered part of the same facility.

Federal Energy Regulatory Commission Cushion or *FERC Cushion* means the minimum natural gas capacity of a storage field as determined by the Federal Energy Regulatory Commission.

Flame zone means the portion of the combustion chamber in a combustion device occupied by the flame envelope.

Flash tank. See the definition for gas-condensate-glycol (GCG) separator.

Flow indicator means a device which indicates whether gas flow is present in

a line or whether the valve position would allow gas flow to be present in a line.

Gas-condensate-glycol (GCG) separator means a two-or three-phase separator through which the "rich" glycol stream of a glycol dehydration unit is passed to remove entrained gas and hydrocarbon liquid. The GCG separator is commonly referred to as a flash separator or flash tank.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

Glycol dehydration unit baseline operations means operations representative of the glycol dehydration unit operations as of June 17, 1999. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, glycol dehydration unit baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (i.e., at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

Glycol dehydration unit process vent means either the glycol dehydration unit reboiler vent and the vent from the GCG separator (flash tank), if present.

Glycol dehydration unit reboiler vent means the vent through which exhaust from the reboiler of a glycol dehydration unit passes from the reboiler to the atmosphere or to a control device.

Hazardous air pollutants or *HAP* means the chemical compounds listed in section 112(b) of the Clean Air Act (Act). All chemical compounds listed in section 112(b) of the Act need to be considered when making a major source determination. Only the HAP compounds listed in Table 1 of this subpart need to be considered when determining compliance.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. Any energy recovery section is not physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section is a separate section following the combustion section and the two are joined by ducts or connections carrying flue gas. The above energy recovery section limitation does not apply to an energy recovery section used solely to preheat the incoming vent stream or combustion air.

Initial startup means the first time a new or reconstructed source begins production. For the purposes of this subpart, initial startup does not include subsequent startups (as defined in this section) of equipment, for example, following malfunctions or shutdowns.

Major source, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control; and

(2) Emissions from processes, operations, and equipment that are not part of the same facility, as defined in this section, shall not be aggregated.

Natural gas means a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface. The principal hydrocarbon constituent is methane.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

No detectable emissions means no escape of HAP from a device or system to the atmosphere as determined by:

(1) Instrument monitoring results in accordance with the requirements of § 63.1282(b); and

(2) The absence of visible openings or defects in the device or system, such as rips, tears, or gaps.

Operating parameter value means a minimum or maximum value established for a control device or process parameter which, if achieved by itself or in combination with one or more other operating parameter values, indicates that an owner or operator has complied with an applicable operating parameter limitation, over the appropriate averaging period as specified in § 63.1282 (e) and (f).

Operating permit means a permit required by 40 CFR part 70 or part 71.

Organic monitoring device means an instrument used to indicate the concentration level of organic compounds exiting a control device based on a detection principle such as infra-red, photoionization, or thermal conductivity.

Primary fuel means the fuel that provides the principal heat input (i.e., more than 50 percent) to the device. To be considered primary, the fuel must be able to sustain operation without the addition of other fuels.

Process heater means an enclosed device using a controlled flame, the primary purpose of which is to transfer heat to a process fluid or process material that is not a fluid, or to a heat transfer material for use in a process (rather than for steam generation).

Safety device means a device that meets both of the following conditions: the device is not used for planned or routine venting of liquids, gases, or fumes from the unit or equipment on which the device is installed; and the device remains in a closed, sealed position at all times except when an unplanned event requires that the device open for the purpose of preventing physical damage or permanent deformation of the unit or equipment on which the device is installed in accordance with good engineering and safety practices for handling flammable, combustible, explosive, or other hazardous materials. Examples of unplanned events which may require a safety device to open include failure of an essential equipment component or a sudden power outage.

Shutdown means for purposes including, but not limited to, periodic maintenance, replacement of equipment, or repair, the cessation of operation of a glycol dehydration unit, or other affected source under this subpart, or equipment required or used solely to comply with this subpart.

Startup means the setting into operation of a glycol dehydration unit, or other affected equipment under this subpart, or equipment required or used to comply with this subpart. Startup includes initial startup and operation solely for the purpose of testing equipment.

Storage vessel means a tank or other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, produced water, or other liquid, and is constructed primarily of non-earthen

materials (e.g., wood, concrete, steel, plastic) that provide structural support.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Temperature monitoring device means an instrument used to monitor temperature and having a minimum accuracy of ±2 percent of the temperature being monitored expressed in °C, or ±2.5 °C, whichever is greater. The temperature monitoring device may measure temperature in degrees Fahrenheit or degrees Celsius, or both.

Total organic compounds or *TOC*, as used in this subpart, means those compounds which can be measured according to the procedures of Method 18, 40 CFR part 60, appendix A.

Underground storage means the subsurface facilities utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at an underground storage facility include, but are not limited to, compression and dehydration.

§ 63.1272 Startups, shutdowns, and malfunctions.

(a) The provisions set forth in this subpart shall apply at all times except during startups or shutdowns, during malfunctions, and during periods of non-operation of the affected sources (or specific portion thereof) resulting in cessation of the emissions to which this subpart applies. However, during the startup, shutdown, malfunction, or period of non-operation of one portion of an affected source, all emission points which can comply with the specific provisions to which they are subject must do so during the startup, shutdown, malfunction, or period of non-operation.

(b) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the provisions of this subpart during times when emissions are being routed to such items of equipment, if the shutdown would contravene requirements of this subpart applicable to such items of equipment. This paragraph does not apply if the item of equipment is malfunctioning, or if the owner or operator must shut down the equipment to avoid damage due to a contemporaneous startup, shutdown, or malfunction of the affected source or a portion thereof.

(c) During startups, shutdowns, and malfunctions when the requirements of this subpart do not apply pursuant to paragraphs (a) and (b) of this section, the owner or operator shall implement, to the extent reasonably available, measures to prevent or minimize excess emissions to the maximum extent practical. For purposes of this paragraph, the term "excess emissions" means emissions in excess of those that would have occurred if there were no startup, shutdown, or malfunction, and the owner or operator complied with the relevant provisions of this subpart. The measures to be taken shall be identified in the applicable startup, shutdown, and malfunction plan, and may include, but are not limited to, air pollution control technologies, recovery technologies, work practices, pollution prevention, monitoring, and/or changes in the manner of operation of the source. Back-up control devices are not required, but may be used if available.

(d) The owner or operator shall prepare a startup, shutdown, or malfunction plan as required in § 63.6(e)(3) except that the plan is not required to be incorporated by reference into the source's title V permit as specified in § 63.6(e)(3)(i). Instead, the owner or operator shall keep the plan on record as required by § 63.6(e)(3)(v). The failure of the plan to adequately minimize emissions during the startup, shutdown, or malfunction does not shield an owner or operator from enforcement actions.

§ 63.1273 [Reserved]

§ 63.1274 General standards.

(a) Table 2 of this subpart specifies the provisions of subpart A (General Provisions) that apply and those that do not apply to owners and operators of affected sources subject to this subpart.

(b) All reports required under this subpart shall be sent to the Administrator at the appropriate address listed in § 63.13. Reports may be submitted on electronic media.

(c) Except as specified in paragraph (d) of this section, the owner or operator of an affected source (i.e., glycol dehydration unit) located at an existing or new major source of HAP emissions shall comply with the requirements in this subpart as follows:

(1) The control requirements for glycol dehydration unit process vents specified in § 63.1275;

(2) The monitoring requirements specified in § 63.1283, and

(3) The recordkeeping and reporting requirements specified in §§ 63.1284 and 63.1285.

(d) *Exemptions.* The owner or operator is exempt from the requirements of paragraph (c) of this section if the criteria listed in paragraph (d)(1) or (d)(2) of this section are met. Records of the determination of these criteria must be maintained as required in § 63.1284(d) of this subpart.

(1) The actual annual average flow of gas to the glycol dehydration unit is less than 283 thousand standard cubic meters per day, as determined by the procedures specified in § 63.1282(a)(1) of this subpart; or

(2) The actual average emissions of benzene from the glycol dehydration unit process vents to the atmosphere are less than 0.90 megagram per year as determined by the procedures specified in § 63.1282(a)(2) of this subpart.

(e) Each owner or operator of a major HAP source subject to this subpart is required to apply for a part 70 or part 71 operating permit from the appropriate permitting authority. If the Administrator has approved a State operating permit program under part 70, the permit shall be obtained from the State authority. If a State operating permit program has not been approved, the owner or operator shall apply to the EPA Regional Office pursuant to part 71.

(f) [Reserved]

(g) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, a leak is detected and the owner or operator shall take further action as required by the applicable provisions of this subpart.

§ 63.1275 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit, subject to this subpart, with an actual annual average natural gas flowrate equal to or greater than 283 thousand standard cubic meters per day and with actual average benzene glycol dehydration unit process vent emissions equal to or greater than 0.90 megagrams per year.

(b) Except as provided in paragraph (c) of this section, an owner or operator of a glycol dehydration unit process vent shall comply with the requirements specified in paragraphs (b)(1) and (b)(2) of this section.

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i) or (b)(1)(ii) of this section.

(i) The owner or operator shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(d).

(ii) The owner or operator shall connect the process vent to a control device or a combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be less than 0.90 megagrams per year. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(d), except that the performance requirements specified in § 63.1281(d)(1)(i) and (ii) do not apply.

(2) One or more safety devices that vent directly to the atmosphere may be used on the air emission control equipment installed to comply with paragraph (b)(1) of this section.

(c) As an alternative to the requirements of paragraph (b) of this section, the owner or operator may comply with one of the following

(1) The owner or operator shall control air emissions by connecting the process vent to a process natural gas line.

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the glycol dehydration unit process vent are reduced by 95.0 percent through process modifications or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.1281(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraphs (c)(3)(i) through (c)(3)(ii), through the installation and operation of controls as specified in paragraph (b) (1) of this section.

(i) HAP emissions are reduced by 95.0 percent or more.

(ii) Benzene emissions are reduced to a level less than 0.90 megagrams per year.

§ 63.1276–§ 63.1280 [Reserved]

§ 63.1281 Control equipment requirements.

(a) This section applies to each closed-vent system and control device installed and operated by the owner or operator to control air emissions as required by the provisions of this subpart. Compliance with paragraphs (c) and (d) of this section will be determined by review of the records required by § 63.1284, the reports required by § 63.1285, by review of performance test results, and by inspections.

(b) [Reserved]

(c) *Closed-vent system requirements.* (1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in a HAP emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

(2) The closed-vent system shall be designed and operated with no detectable emissions.

(3) If the closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, the owner or operator shall meet the requirements specified in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(i) For each bypass device, except as provided for in paragraph (c)(3)(ii) of this section, the owner or operator shall either:

(A) Properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere that takes a reading at least once every 15 minutes, and that sounds an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device to the atmosphere; or

(B) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration. The owner or operator shall visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

(d) *Control device requirements.* (1) The control device used to reduce HAP emissions in accordance with the standards of this subpart shall be one of the control devices specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated in accordance with one of the following performance requirements:

(A) Reduces the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater, as determined in accordance with the requirements of § 63.1282(d);

(B) Reduces the concentration of either TOC or total HAP in the exhaust gases at the outlet to the device to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 63.1282(d); or

(C) Operates at a minimum residence time of 0.5 second at a minimum temperature of 760 °C.

(D) If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(ii) A vapor recovery device (e.g., carbon adsorption system or condenser) or other control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.1282(d).

(iii) A flare that is designed and operated in accordance with the requirements of § 63.11(b).

(2) [Reserved]

(3) The owner or operator shall demonstrate that a control device achieves the performance requirements of paragraph (d)(1) of this section by following the procedures specified in § 63.1282(d).

(4) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the emissions unit or units through the closed-vent system to the control device, as required under § 63.1275, except when maintenance or repair of a unit cannot be completed without a shutdown of the control device. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of

§ 63.1283(d), the owner or operator shall demonstrate compliance according to the requirements of § 63.1282(e), or (f) as applicable.

(5) For each carbon adsorption system used as a control device to meet the requirements of paragraph (d)(1) of this section, the owner or operator shall manage the carbon as follows:

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system.

(ii) The spent carbon removed from the carbon adsorption system shall be either regenerated, reactivated, or burned in one of the units specified in paragraphs (d)(5)(ii)(A) through (d)(5)(ii)(G) of this section.

(A) Regenerated or reactivated in a thermal treatment unit for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(B) Regenerated or reactivated in a thermal treatment unit equipped with and operating organic air emission controls in accordance with this section.

(C) Regenerated or reactivated in a thermal treatment unit equipped with and operating organic air emission controls in accordance with a national emissions standard for HAP under another subpart in 40 CFR part 61 or this part.

(D) Burned in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(E) Burned in a hazardous waste incinerator which the owner or operator has designed and operates in accordance with the requirements of 40 CFR part 265, subpart O.

(F) Burned in a boiler or industrial furnace for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(G) Burned in a boiler or industrial furnace which the owner or operator has designed and operates in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(e) *Process modification requirements.* Each owner or operator that chooses to comply with § 63.1275(c)(2) shall meet the requirements specified in paragraphs (e)(1) through (e)(3) of this section.

(1) The owner or operator shall determine glycol dehydration unit baseline operations (as defined in § 63.1271). Records of glycol dehydration unit baseline operations shall be retained as required under § 63.1284(b)(9).

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the percent HAP reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including, but not limited to, changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall HAP emission reduction.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (e)(3)(ii) of this section.

(i) The owner or operator shall maintain records, as required in § 63.1284(b)(10), that the facility continues to operate in accordance with the conditions specified under paragraph (e)(2) of this section.

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) of this section, except that the emission reduction achieved shall be the emission reduction specified in paragraph (e)(2) of this section.

§ 63.1282 Test methods, compliance procedures, and compliance demonstrations.

(a) *Determination of glycol dehydration unit flowrate or benzene emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate or benzene emissions to meet the criteria for the exemption from control requirements under § 63.1274(d).

(1) The determination of actual flowrate of natural gas to a glycol dehydration unit shall be made using the procedures of either paragraph (a)(1)(i) or (a)(1)(ii) of this section.

(i) The owner or operator shall install and operate a monitoring instrument that directly measures natural gas flowrate to the glycol dehydration unit with an accuracy of plus or minus 2 percent or better. The owner or operator shall convert the annual natural gas flowrate to a daily average by dividing the annual flowrate by the number of days per year the glycol dehydration unit processed natural gas.

(ii) The owner or operator shall document, to the Administrator's satisfaction, that the actual annual average natural gas flowrate to the glycol dehydration unit is less than 85 thousand standard cubic meters per day.

(2) The determination of actual average benzene emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (a)(2)(i) or (a)(2)(ii) of this section. Emissions shall be determined either uncontrolled or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene emissions using the model GRI-GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI-GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene emissions in kilograms per hour through direct measurement by performing three runs of Method 18 in 40 CFR part 60, appendix A (or an equivalent method), and averaging the results of the three runs. Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

(b) *No detectable emissions test procedure.* (1) The procedure shall be conducted in accordance with Method 21, 40 CFR part 60, appendix A.

(2) The detection instrument shall meet the performance criteria of Method 21, 40 CFR part 60, appendix A, except the instrument response factor criteria

in section 3.1.2(a) of Method 21 shall be for the average composition of the fluid, and not for each individual organic compound in the stream.

(3) The detection instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21, 40 CFR part 60, appendix A.

(4) Calibration gases shall be as follows:

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air); and

(ii) A mixture of methane in air at a methane concentration of less than 10,000 parts per million by volume.

(5) An owner or operator may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If an owner or operator chooses to adjust the instrument readings for the background level, the background level value must be determined according to the procedures in Method 21 of 40 CFR part 60, appendix A.

(6)(i) Except as provided in paragraph (b)(6)(i) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the process fluid not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts which are not organic hazardous air pollutants or volatile organic compounds, the average stream response factor shall be calculated on an inert-free basis.

(ii) If no instrument is available at the facility that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, the instrument readings may be adjusted by multiplying by the average response factor of the process fluid, calculated on an inert-free basis as described in paragraph (b)(6)(i) of this section.

(7) An owner or operator must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (b)(7)(ii) of this section.

(i) If an owner or operator chooses not to adjust the detection instrument readings for the background organic concentration level, then the maximum organic concentration value measured by the detection instrument is compared directly to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If an owner or operator chooses to adjust the detection instrument readings for the background organic concentration level, the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section is compared with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) is less than 500 parts per million by volume.

(c) [Reserved]

(d) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1) or (e)(3)(ii) using either a performance test as specified in paragraph (d)(3) of this section or a design analysis as specified in paragraph (d)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (d)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent.

(1) The following control devices are exempt from the requirements to conduct performance tests and design analyses under this section:

(i) A flare that is designed and operated in accordance with § 63.11(b);

(ii) A boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) A boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H, or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) A hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O, or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(vi) A control device for which a performance test was conducted for determining compliance with a regulation promulgated by the EPA, and the test was conducted using the same methods specified in this section, and either no process changes have been made since the test, or the owner or operator can demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process changes.

(2) An owner or operator shall design and operate each flare in accordance with the requirements specified in § 63.11(b) and in paragraphs (d)(2)(i) and (d)(2)(ii) of this section.

(i) The compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(ii) An owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration when a flare is used.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.1281(d)(1) or (e)(3)(ii), the owner or operator shall use the test methods and procedures specified in paragraphs (d)(3)(i) through (d)(3)(iv) of this section. The performance test shall be conducted according to the schedule specified in § 63.7(a)(2), and the results of the performance test shall be submitted in the Notification of Compliance Status Report as required in § 63.1285(d)(1)(ii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites specified in paragraphs (d)(3)(i)(A) and (B) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(A) To determine compliance with the control device percent reduction requirements specified in § 63.1281(d)(1)(i)(A),(d)(1)(ii), or (e)(3)(ii), sampling sites shall be located at the inlet of the first control device and at the outlet of the final control device.

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), the sampling site shall be located at the outlet of the device.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) To determine compliance with the control device percent reduction performance requirement in § 63.1281(d)(1)(i)(A), 63.1281(d)(1)(ii), or 63.1281(e)(3)(ii), the owner or operator shall use either Method 18, 40 CFR part 60, appendix A, or Method 25A, 40 CFR part 60, appendix A;

alternatively, any other method or data that have been validated according to the applicable procedures in Method 301 of appendix A of this part may be used. The following procedures shall be used to calculate the percentage of reduction:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of either TOC (minus methane and ethane) or total HAP (E_i, E_o) shall be computed.

(*1*) The following equations shall be used:

$$E_i = K_2\left(\sum_{j=1}^{n} C_{ij} M_{ij}\right) Q_i$$

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj} M_{oj}\right) Q_o$$

Where:

C_{ij}, C_{oj} = Concentration of sample component j of the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

E_i, E_o = Mass rate of TOC (minus methane and ethane) or total HAP at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

M_{ij}, M_{oj} = Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

K_2 = Constant, 2.494×10^{-6} (parts per million)$^{-1}$ (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature is 20°C.

(*2*) When the TOC mass rate is calculated, all organic compounds (minus methane and ethane) measured by Method 18, of 40 CFR part 60, appendix A; or Method 25A, 40 CFR part 60, appendix A, shall be summed using the equations in paragraph (d)(3)(iii)(B)(*1*) of this section.

(*3*) When the total HAP mass rate is calculated, only HAP chemicals listed in Table 1 of this subpart shall be summed using the equations in paragraph (d)(3)(iii)(B)(*1*) of this section.

(C) The percentage of reduction in TOC (minus methane and ethane) or total HAP shall be calculated as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} \times 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) or total HAP at the inlet to the control device as calculated under paragraph (d)(3)(iii)(B) of this section, kilograms TOC per hour or kilograms HAP per hour.

E_o = Mass rate of TOC (minus methane and ethane) or total HAP at the outlet of the control device, as calculated under paragraph (d)(3)(iii)(B) of this section, kilograms TOC per hour or kilograms HAP per hour.

(D) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, the weight-percentage of reduction of total HAP or TOC (minus methane and ethane) across the device shall be determined by comparing the TOC (minus methane and ethane) or total HAP in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) or total HAP exiting the device, respectively.

(iv) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), the owner or operator shall use either Method 18, 40 CFR part 60, appendix A; or Method 25A, 40 CFR part 60, appendix A, to measure either TOC (minus methane and ethane) or total HAP. Alternatively, any other method or data that have been validated according to Method 301 of appendix A of this part, may be used. The following procedures shall be used to calculate parts per million by volume concentration, corrected to 3 percent oxygen:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The TOC concentration or total HAP concentration shall be calculated according to paragraph (d)(3)(iv)(B)(*1*) or (d)(3)(iv)(B)(*2*) of this section.

(*1*) The TOC concentration (C_{TOC}) is the sum of the concentrations of the individual components and shall be computed for each run using the following equation:

$$C_{TOC} = \sum_{i=1}^{x} \frac{\left(\sum_{j=1}^{n} C_{ji}\right)}{x}$$

Where:

C_{TOC} = Concentration of total organic compounds minus methane and ethane, dry basis, parts per million by volume.

C_{ji} = Concentration of sample components j of sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(*2*) The total HAP concentration (C_{HAP}) shall be computed according to the equation in paragraph (d)(3)(iv)(B)(*1*) of this section, except that only HAP chemicals listed in Table 1 of this subpart shall be summed.

(C) The TOC concentration or total HAP concentration shall be corrected to 3 percent oxygen as follows:

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3B, 40 CFR part 60, appendix A, shall be used to determine the oxygen concentration (% O_{2d}). The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

(*2*) The concentration corrected to 3 percent oxygen (C_c) shall be computed using the following equation:

$$C_c = C_m\left(\frac{17.9}{20.9 - \%O_{2d}}\right)$$

Where:

C_c = TOC concentration of total HAP concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_m = TOC concentration or total HAP concentration, dry basis, parts per million by volume.

% O_{2d} = Concentration of oxygen, dry basis, percent by volume.

(4) For a design analysis conducted to meet the requirements of § 63.1281(d)(1) or (e)(3)(ii), the owner or operator shall meet the requirements specified in paragraphs (d)(4)(i) and (d)(4)(ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.1285(d)(1)(i).

(i) The design analysis shall include analysis of the vent stream characteristics and control device

operating parameters for the applicable control device as specified in paragraphs (d)(4)(i) (A) through (F) of this section.

(A) For a thermal vapor incinerator, the design analysis shall include the vent stream composition, constituent concentrations, and flowrate and shall establish the design minimum and average temperatures in the combustion zone and the combustion zone residence time.

(B) For a catalytic vapor incinerator, the design analysis shall include the vent stream composition, constituent concentrations, and flowrate and shall establish the design minimum and average temperatures across the catalyst bed inlet and outlet, and the design service life of the catalyst.

(C) For a boiler or process heater, the design analysis shall include the vent stream composition, constituent concentrations, and flowrate; shall establish the design minimum and average flame zone temperatures and combustion zone residence time; and shall describe the method and location where the vent stream is introduced into the flame zone.

(D) For a condenser, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the design analysis, an owner or operator may elect to use the procedures specified in paragraph (d)(5) of this section.

(E) For a regenerable carbon adsorption, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(F) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(ii) If the owner or operator and the Administrator do not agree on a demonstration of control device performance using a design analysis, then the disagreement shall be resolved using the results of a performance test performed by the owner or operator in accordance with the requirements of paragraph (d)(3) of this section. The Administrator may choose to have an authorized representative observe the performance test.

(5) As an alternative to the procedures in paragraphs (d)(3) and (d)(4)(i)(D) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions," (GRI-95/0368.1) as inputs for the model GRI-GLYCalc™, Version 3.0 or higher, to determine condenser performance.

(e) *Compliance demonstration for control devices performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.1281(d)(1) and (e)(3)(ii). Compliance shall be demonstrated using the requirements in paragraphs (e)(1) through (e)(3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.1281(d)(2)(ii) or § 63.1275(c)(2), may demonstrate compliance according to paragraph (f) of this section. An owner or operator may switch between compliance with paragraph (e) of this section and compliance with paragraph (f) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.1285(e), following the change.

(1) The owner or operator shall establish a site specific maximum or minimum monitoring parameter value (as appropriate) according to the requirements of § 63.1283(d)(5)(i).

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.1283(d)(4).

(3) Compliance is achieved when the daily average of the monitoring parameter value calculated under paragraph (e)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (e)(1) of this section.

(f) *Compliance demonstration with percent reduction performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.1281(d)(1)(ii) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (f)(1) through (f)(3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to the procedures specified in § 63.1283(d)(5)(ii).

(2) Compliance with the percent reduction requirement in § 63.1281(d)(1)(ii) or § 63.1275(c)(2) shall be demonstrated by the procedures in paragraphs (f)(2)(i) through (f)(2)(iii) of this section.

(i) The owner or operator must calculate the daily average condenser outlet temperature in accordance with § 63.1283(d)(4).

(ii) The owner or operator shall determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated in paragraph (f)(2)(i) of this section and the condenser performance curve established in paragraph (f)(1) of this section.

(iii) Except as provided in paragraphs (f)(2)(iii) (A), (B), and (D) of this section, at the end of each operating day the owner or operator shall calculate the 30-day average HAP emission reduction from the condenser efficiencies determined in paragraph (f)(2)(ii) of this section for the preceding 30 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.1275(c)(2), the 30-day average HAP emission reduction shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency determined in paragraph (f)(2)(ii) of this section, both for the preceding 30 operating days.

(A) After the compliance date specified in § 63.1270(f), an owner or operator of a facility that stores natural gas that has less than 30 days of data for determining the average HAP emission reduction, shall calculate the cumulative average at the end of the withdrawal season, each season, until 30 days of condenser operating data are

accumulated. For a facility that does not store natural gas, the owner or operator that has less than 30 days of data for determining average HAP emission reduction, shall calculate the cumulative average at the end of the calendar year, each year, until 30 days of condenser operating data are accumulated.

(B) After the compliance date specified in § 63.1270(f), an owner or operator that has less than 30 days of data for determining the average HAP emission reduction, compliance is achieved if the average HAP emission reduction calculated in paragraph (f)(2)(iii)(A) of this section, is equal to or greater than 95.0 percent.

(C) For the purposes of this subpart, a withdrawal season begins the first time gas is withdrawn from the storage field after July 1 of the calendar year and ends on June 30 of the next calendar year.

(D) Glycol dehydration units that are operated continuously have the option of complying with the requirements specified in 40 CFR 63.772(g).

(3) Compliance is achieved with the emission limitation specified in § 63.1281(d)(1)(ii) or § 63.1275(c)(2) if the average HAP emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than 95.0 percent.

§ 63.1283 Inspection and monitoring requirements.

(a) This section applies to an owner or operator using air emission controls in accordance with the requirements of § 63.1275.

(b) [Reserved]

(c) *Closed-vent system inspection and monitoring requirements.* (1) For each closed-vent system required to comply with this section, the owner or operator shall comply with the requirements of paragraphs (c)(2) through (7) of this section.

(2) Except as provided in paragraphs (c) (5) and (6) of this section, each closed-vent system shall be inspected according to the procedures and schedule specified in paragraphs (c)(2) (i) and (ii) of this section.

(i) For each closed-vent system joints, seams, or other connections that are permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted or gasketed ducting flange), the owner or operator shall:

(A) Conduct an initial inspection according to the procedures specified in § 63.1282(b) to demonstrate that the closed-vent system operates with no detectable emissions.

(B) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; or broken or missing caps or other closure devices. The owner or operator shall monitor a component or connection using the procedures specified in § 63.1282(b) to demonstrate that it operates with no detectable emissions following any time the component or connection is repaired or replaced or the connection is unsealed.

(ii) For closed-vent system components other than those specified in paragraph (c)(2)(i) of this section, the owner or operator shall:

(A) Conduct an initial inspection according to the procedures specified in § 63.1282(b) to demonstrate that the closed-vent system operates with no detectable emissions.

(B) Conduct annual inspections according to the procedures specified in § 63.1282(b) to demonstrate that the components or connections operate with no detectable emissions.

(C) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; or broken or missing caps or other closure devices.

(3) In the event that a leak or defect is detected, the owner or operator shall repair the leak or defect as soon as practicable, except as provided in paragraph (c)(4) of this section.

(i) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(ii) Repair shall be completed no later than 15 calendar days after the leak is detected.

(4) Delay of repair of a closed-vent system for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, as defined in § 63.1271, 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 completed by the end of the next shutdown.

(5) Any parts of the closed-vent system or cover that are designated, as described in paragraphs (c)(5) (i) and (ii) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (c)(2) (i) and (ii) of this section if:

(i) 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 paragraph (c)(2) (i) or (ii) of this section; and

(ii) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(6) Any parts of the closed-vent system or cover that are designated, as described in paragraphs (c)(6) (i) and (ii) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (c)(2) (i) and (ii) of this section if:

(i) 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

(ii) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years.

(7) Records shall be maintained as specified in § 63.1284(b)(5) through (8).

(d) *Control device monitoring requirements.* (1) For each control device except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (9) of this section that will allow a determination to be made whether the control device is achieving the applicable performance requirements of § 63.1281(d) or (e)(3). The continuous parameter monitoring system must meet the following specifications and requirements:

(i) Each continuous parameter monitoring system shall measure data values at least once every hour and record either:

(A) Each measured data value; or

(B) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(ii) The monitoring system must be installed, calibrated, operated, and maintained in accordance with the manufacturer's specifications or other written procedures that provide reasonable assurance that the monitoring equipment is operating properly.

(2) An owner or operator is exempted from the monitoring requirements specified in paragraphs (d)(3) through (9) of this section for the following types of control devices:

(i) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel;

(ii) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) The owner or operator shall install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(3)(i), (d)(3)(ii), or (d)(3)(iii) of this section.

(i) A continuous monitoring system that measures the following operating parameters as applicable:

(A) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location in the combustion chamber downstream of the combustion zone.

(B) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperatures at two locations and have a minimum accuracy of ±2 percent of the temperatures being monitored in °C, or ±2.5 °C, whichever value is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(C) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(D) For a boiler or process heater with a design heat input capacity of less than 44 megawatts, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location in the combustion chamber downstream of the combustion zone.

(E) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location in the exhaust vent stream from the condenser.

(F) For a regenerative-type carbon adsorption system:

(*1*) A continuous parameter monitoring system to measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The integrating regenerating stream flow monitoring device must have an accuracy of ±10 percent; and

(*2*) A continuous parameter monitoring system to measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and to measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater.

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.1282(d)(3) or a design analysis in accordance with § 63.1282(d)(4)(i)(F) and shall be based on the total carbon working capacity of the control device and source operating schedule.

(ii) A continuous monitoring system that measures the concentration level of organic compounds in the exhaust vent stream from the control device using an organic monitoring device equipped with a continuous recorder. The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B of 40 CFR part 60 and must be installed, calibrated, and maintained according to the manufacturer's specifications.

(iii) A continuous monitoring system that measures alternative operating parameters other than those specified in paragraph (d)(3)(i) or (d)(3)(ii) of this section upon approval of the Administrator as specified in § 63.8(f)(1) through (5).

(4) Using the data recorded by the monitoring system, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If HAP emissions unit operation is continuous, the operating day is a 24-hour period. If the HAP emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) For each operating parameter monitored in accordance with the requirements of paragraph (d)(3) of this section, the owner or operator shall comply with paragraph (d)(5)(i) of this section for all control devices, and when condensers are installed, the owner or operator shall also comply with paragraph (d)(5)(ii) of this section for condensers.

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.1281(d)(1) or (e)(3)(ii). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1) or (e)(3)(ii), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by control device design analysis or control device manufacturer's recommendations or a combination of both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.1282(d)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1) or (e)(3)(ii), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the control device design analysis and may be supplemented by the control device manufacturer's recommendations.

(ii) The owner or operator shall establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency. The curve shall be established as follows:

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.1281(d)(1) or (e)(3)(ii), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device

manufacturer's recommendations, or a combination or both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.1282(d)(4)(i)(D) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.1281(d)(1) or (e)(3)(ii), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraphs (d)(5)(ii)(A) and (B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1) as inputs for the model GRI-GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(6) An excursion for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (d)(6)(i) through (d)(6)(iv) of this section being met. When multiple operating parameters are monitored for the same control device and during the same operating day, and more than one of these operating parameters meets an excursion criterion specified in paragraphs (d)(6)(i) through (d)(6)(iv) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(i) An excursion occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established for the operating parameter in accordance with the requirements of paragraph (d)(5)(i) of this section.

(ii) An excursion occurs when average condenser efficiency calculated according to the requirements specified in § 63.1282(f)(2)(iii) is less than 95.0 percent, as specified in § 63.1282(f)(3).

(iii) An excursion occurs when the monitoring data are not available for at least 75 percent of the operating hours.

(iv) If the closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, an excursion occurs when:

(A) For each bypass line subject to § 63.1281(c)(3)(i)(A) the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(B) For each bypass line subject to § 63.1281(c)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(7) For each excursion, except as provided for in paragraph (d)(8) of this section, the owner or operator shall be deemed to have failed to have applied control in a manner that achieves the required operating parameter limits. Failure to achieve the required operating parameter limits is a violation of this standard.

(8) An excursion is not a violation of the operating parameter limit as specified in paragraphs (d)(8)(i) and (d)(8)(ii) of this section.

(i) An excursion does not count toward the number of excused excursions allowed under paragraph (d)(8)(ii) of this section when the excursion occurs during any one of the following periods:

(A) During a period of startup, shutdown, or malfunction when the affected facility is operated during such period in accordance with the facility's startup, shutdown, and malfunction plan; or

(B) During periods of non-operation of the unit or the process that is vented to the control device (resulting in cessation of HAP emissions to which the monitoring applies).

(ii) For each control device, or combinations of control devices, installed on the same HAP emissions unit, one excused excursion is allowed per semiannual period for any reason. The initial semiannual period is the 6-month reporting period addressed by the first Periodic Report submitted by the owner or operator in accordance with § 63.1285(e) of this subpart.

(9) Nothing in paragraphs (d)(1) through (d)(8) of this section shall be construed to allow or excuse a monitoring parameter excursion caused by any activity that violates other applicable provisions of this subpart.

§ 63.1284 Recordkeeping requirements.

(a) The recordkeeping provisions of subpart A of this part, that apply and those that do not apply to owners and operators of facilities subject to this subpart are listed in Table 2 of this subpart.

(b) Except as specified in paragraphs (c) and (d) of this section, each owner or operator of a facility subject to this subpart shall maintain the records specified in paragraphs (b)(1) through (b)(10) of this section:

(1) The owner or operator of an affected source subject to the provisions of this subpart shall maintain files of all information (including all reports and notifications) required by this subpart. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report or period.

(i) All applicable records shall be maintained in such a manner that they can be readily accessed.

(ii) The most recent 12 months of records shall be retained on site or shall be accessible from a central location by computer or other means that provides access within 2 hours after a request.

(iii) The remaining 4 years of records may be retained offsite.

(iv) Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

(2) Records specified in § 63.10(b)(2);

(3) Records specified in § 63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of § 63.1283(d). Notwithstanding the previous sentence, monitoring data recorded during periods identified in paragraphs (b)(2)(i) through (b)(2)(iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating.

(i) Monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments;

(ii) Startup, shutdown, and malfunction events. During startup, shutdown and malfunction events, the owner or operator shall maintain records indicating whether or not the startup, shutdown, or malfunction plan, required under § 63.1272(d), was followed.

(iii) Periods of non-operation resulting in cessation of the emissions to which the monitoring applies; and

(iv) Excursions due to invalid data as defined in § 63.1283(d)(6)(iii).

(4) Each owner or operator using a control device to comply with § 63.1274 shall keep the following records up-to-date and readily accessible:

(i) Continuous records of the equipment operating parameters specified to be monitored under § 63.1283(d) or specified by the Administrator in accordance with § 63.1283(d)(3)(iii). For flares, the hourly records and records of pilot flame outages specified in § 63.1283(d)(3)(i)(C) shall be maintained in place of continuous records.

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.1283(d)(4) of this subpart. For flares, records of the times and duration of all periods during which all pilot flames are absent shall be kept rather than daily averages.

(iii) Hourly records of whether the flow indicator specified under § 63.1281(c)(3)(i)(A) was operating and whether flow was detected at any time during the hour, as well as records of the times and durations of all periods when the vent stream is diverted from the control device or the monitor is not operating.

(iv) Where a seal or closure mechanism is used to comply with § 63.1281(c)(3)(i)(B), hourly records of flow are not required. In such cases, the owner or operator shall record that the monthly visual inspection of the seals or closure mechanism has been done, and shall record the duration of all periods when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out, and records of any car-seal that has broken.

(5) Records identifying all parts of the closed-vent system that are designated as unsafe to inspect in accordance with § 63.1283(c)(5), an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(6) Records identifying all parts of the closed-vent system that are designated as difficult to inspect in accordance with § 63.1283(c)(6), an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(7) For each inspection conducted in accordance with § 63.1283(c), during which a leak or defect is detected, a record of the information specified in paragraphs (b)(7)(i) through (b)(7)(viii) of this section.

(i) The instrument identification numbers, operator name or initials, and identification of the equipment.

(ii) The date the leak or defect was detected and the date of the first attempt to repair the leak or defect.

(iii) Maximum instrument reading measured by the method specified in § 63.1283(c)(3) after the leak or defect is successfully repaired or determined to be nonrepairable.

(iv) "Repair delayed" and the reason for the delay if a leak or defect is not repaired within 15 calendar days after discovery of the leak or defect.

(v) The name, initials, or other form of identification of the owner or operator (or designee) whose decision it was that repair could not be effected without a shutdown.

(vi) The expected date of successful repair of the leak or defect if a leak or defect is not repaired within 15 calendar days.

(vii) Dates of shutdowns that occur while the equipment is unrepaired.

(viii) The date of successful repair of the leak or defect.

(8) For each inspection conducted in accordance with § 63.1283(c) during which no leaks or defects are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks or defects were detected.

(9) Records of glycol dehydration unit baseline operations calculated as required under § 63.1281(e)(1).

(10) Records required in § 63.1281(e)(3)(i) documenting that the facility continues to operate under the conditions specified in § 63.1281(e)(2).

(c) An owner or operator that elects to comply with the benzene emission limit specified in § 63.1275(b)(1)(ii) shall document, to the Administrator's satisfaction, the following items:

(1) The method used for achieving compliance and the basis for using this compliance method; and

(2) The method used for demonstrating compliance with 0.90 megagrams per year of benzene.

(3) Any information necessary to demonstrate compliance as required in the methods specified in paragraphs (c)(1) and (c)(2) of this section.

(d) An owner or operator that is exempt from control requirements under § 63.1274(d) shall maintain the records specified in paragraph (d)(1) or (d)(2) of this section, as appropriate, for each glycol dehydration unit that is not controlled according to the requirements of § 63.1274(c).

(1) The actual annual average natural gas throughput (in terms of natural gas flowrate to the glycol dehydration unit per day), as determined in accordance with § 63.1282(a)(1); or

(2) The actual average benzene emissions (in terms of benzene emissions per year), as determined in accordance with § 63.1282(a)(2).

(e) Record the following when using a flare to comply with § 63.1281(d):

(1) Flare design (i.e., steam-assisted, air-assisted, or non-assisted);

(2) All visible emission readings, heat content determinations, flowrate measurements, and exit velocity determinations made during the compliance determination required by § 63.1282(d)(2); and

(3) All periods during the compliance determination when the pilot flame is absent.

§ 63.1285 Reporting requirements.

(a) The reporting provisions of subpart A, of this part that apply and those that do not apply to owners and operators of facilities subject to this subpart are listed in Table 2 of this subpart.

(b) Each owner or operator of a facility subject to this subpart shall submit the information listed in paragraphs (b)(1) through (b)(6) of this section, except as provided in paragraph (b)(7) of this section.

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000 and plan to be area sources by June 17, 2002 shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(2) The date of the performance evaluation as specified in § 63.8(e)(2), required only if the owner or operator is requested by the Administrator to conduct a performance evaluation for a continuous monitoring system. A separate notification of the performance evaluation is not required if it is included in the initial notification submitted in accordance with paragraph (b)(1) of this section.

(3) The planned date of a performance test at least 60 days before the test in accordance with § 63.7(b). Unless requested by the Administrator, a site-specific test plan is not required by this subpart. If requested by the Administrator, the owner or operator must also submit the site-specific test plan required by § 63.7(c) with the notification of the performance test. A separate notification of the performance test is not required if it is included in the initial notification submitted in accordance with paragraph (b)(1) of this section.

(4) A Notification of Compliance Status Report as described in paragraph (d) of this section;

(5) Periodic Reports as described in paragraph (e) of this section; and

(6) Startup, shutdown, and malfunction reports, as specified in § 63.10(d)(5), shall be submitted as required. Separate startup, shutdown, or malfunction reports as described in § 63.10(d)(5)(i) are not required if the information is included in the Periodic Report specified in paragraph (e) of this section.

(7) Each owner or operator of a glycol dehydration unit subject to this subpart that is exempt from the control

requirements for glycol dehydration unit process vents in § 63.1275, is exempt from all reporting requirements for major sources in this subpart for that unit.

(c) [Reserved]

(d) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status Report as required under § 63.9(h) within 180 days after the compliance date specified in § 63.1270(d). In addition to the information required under § 63.9(h), the Notification of Compliance Status Report shall include the information specified in paragraphs (d)(1) through (d)(10) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If all of the information required under this paragraph have been submitted at any time prior to 180 days after the applicable compliance dates specified in § 63.1270(d), a separate Notification of Compliance Status Report is not required. If an owner or operator submits the information specified in paragraphs (d)(1) through (d)(9) of this section at different times, and/or different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information.

(1) If a closed-vent system and a control device other than a flare are used to comply with § 63.1274, the owner or operator shall submit:

(i) The design analysis documentation specified in § 63.1282(d)(4) of this subpart if the owner or operator elects to prepare a design analysis; or

(ii) If the owner or operator elects to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.1282(d)(3), and that the test conditions are representative of current operating conditions.

(A) The percent reduction of HAP or TOC, or the outlet concentration of HAP or TOC (parts per million by volume on a dry basis), determined as specified in § 63.1282(d)(3) of this subpart; and

(B) The value of the monitored parameters specified in § 63.1283(d) of this subpart, or a site-specific parameter approved by the permitting agency, averaged over the full period of the performance test.

(2) If a closed-vent system and a flare are used to comply with § 63.1274, the owner or operator shall submit performance test results including the information in paragraphs (d)(2)(i) and (ii) of this section.

(i) All visible emission readings, heat content determinations, flowrate measurements, and exit velocity determinations made during the compliance determination required by § 63.1282(d)(2) of this subpart, and

(ii) A statement of whether a flame was present at the pilot light over the full period of the compliance determination.

(3) The owner or operator shall submit one complete test report for each test method used for a particular source.

(i) For additional tests performed using the same test method, the results specified in paragraph (d)(1)(ii) of this section shall be submitted, but a complete test report is not required.

(ii) A complete test report shall include a sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method.

(4) For each control device other than a flare used to meet the requirements of § 63.1274, the owner or operator shall submit the information specified in paragraphs (d)(4)(i) through (iii) of this section for each operating parameter required to be monitored in accordance with the requirements of § 63.1283(d).

(i) The minimum operating parameter value or maximum operating parameter value, as appropriate for the control device, established by the owner or operator to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.1281(d)(1) or (e)(3)(ii).

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.1283(d)(5) of this subpart. This explanation shall include any data and calculations used to develop the value, and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.1281(d)(1) or (e)(3)(ii).

(iii) A definition of the source's operating day for purposes of determining daily average values of monitored parameters. The definition shall specify the times at which an operating day begins and ends.

(5) Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status Report.

(6) After a title V permit has been issued to the owner or operator of an affected source, the owner or operator of such source shall comply with all requirements for compliance status reports contained in the source's title V permit, including reports required under this subpart. After a title V permit has been issued to the owner or operator of an affected source, and each time a notification of compliance status is required under this subpart, the owner or operator of such source shall submit the notification of compliance status to the appropriate permitting authority following completion of the relevant compliance demonstration activity specified in this subpart.

(7) The owner or operator that elects to comply with the requirements of § 63.1275(b)(1)(ii) shall submit the records required under § 63.1284(c).

(8) The owner or operator shall submit an analysis demonstrating whether an affected source is a major source using the maximum throughput calculated according to § 63.1270(a).

(9) The owner or operator shall submit a statement as to whether the source has complied with the requirements of this subpart.

(10) The owner or operator shall submit the analysis prepared under § 63.1281(e)(2) to demonstrate that the conditions by which the facility will be operated to achieve an overall HAP emission reduction of 95.0 percent through process modifications or a combination of process modifications and one or more control devices.

(e) *Periodic Reports.* An owner or operator shall prepare Periodic Reports in accordance with paragraphs (e)(1) and (2) of this section and submit them to the Administrator.

(1) An owner or operator shall submit Periodic Reports semiannually, beginning 60 operating days after the end of the applicable reporting period. The first report shall be submitted no later than 240 days after the date the Notification of Compliance Status Report is due and shall cover the 6-month period beginning on the date the Notification of Compliance Status Report is due.

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (viii) of this section, as applicable.

(i) The information required under § 63.10(e)(3). For the purposes of this

subpart and the information required under § 63.10(e)(3), excursions (as defined in § 63.1283(d)(6)) shall be considered excess emissions.

(ii) A description of all excursions as defined in § 63.1283(d)(6) of this subpart that have occurred during the 6-month reporting period.

(A) For each excursion caused when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit), as specified in § 63.1283(d)(6)(i), the report must include the daily average values of the monitored parameter, the applicable operating parameter limit, and the date and duration of the period that the excursion occurred.

(B) For each excursion caused when the 30-day average condenser control efficiency is less than 95.0 percent, as specified in § 63.1283(d)(6)(ii), the report must include the 30-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

(C) For each excursion caused by lack of monitoring data, as specified in § 63.1283(d)(6)(iii), the report must include the date and duration of period when the monitoring data were not collected and the reason why the data were not collected.

(iii) For each inspection conducted in accordance with § 63.1283(c) during which a leak or defect is detected, the records specified in § 63.1284(b)(7) must be included in the next Periodic Report.

(iv) For each closed-vent system with a bypass line subject to § 63.1281(c)(3)(i)(A), records required under § 63.1284(b)(4)(iii) of all periods when the vent stream is diverted from the control device through a bypass line. For each closed-vent system with a bypass line subject to § 63.1281(c)(3)(i)(B), records required under § 63.1284(b)(4)(iv) of all periods in which the seal or closure mechanism is broken, the bypass valve position has changed, or the key to unlock the bypass line valve was checked out.

(v) If an owner or operator elects to comply with § 63.1275(b)(1)(ii), the records required under § 63.1284(c)(3).

(vi) The information in paragraphs (e)(2)(vi)(A) and (B) of this section shall be stated in the Periodic Report, when applicable.

(A) No excursions.

(B) No continuous monitoring system has been inoperative, out of control, repaired, or adjusted.

(vii) Any change in compliance methods as specified in § 63.1275(b).

(viii) If the owner or operator elects to comply with § 63.1275(c)(2), the records required under § 63.1284(b)(10).

(f) *Notification of process change.* Whenever a process change is made, or a change in any of the information submitted in the Notification of Compliance Status Report, the owner or operator shall submit a report within 180 days after the process change is made or as a part of the next Periodic Report as required under paragraph (e) of this section, whichever is sooner. The report shall include:

(1) A brief description of the process change;

(2) A description of any modification to standard procedures or quality assurance procedures;

(3) Revisions to any of the information reported in the original Notification of Compliance Status Report under paragraph (d) of this section; and

(4) Information required by the Notification of Compliance Status Report under paragraph (d) of this section for changes involving the addition of processes or equipment.

§ 63.1286 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(l) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities will not be delegated to States for §§ 63.1282 and 63.1287 of this subpart.

§ 63.1287 Alternative means of emission limitation.

(a) If, in the judgment of the Administrator, an alternative means of emission limitation will achieve a reduction in HAP emissions at least equivalent to the reduction in HAP emissions from that source achieved under the applicable requirements in §§ 63.1274 through 63.1281, the Administrator will publish a notice in the **Federal Register** permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section shall be published only after public notice and an opportunity for a hearing.

(c) Any person seeking permission to use an alternative means of compliance under this section shall collect, verify, and submit to the Administrator information showing that this means achieves equivalent emission reductions.

§ 63.1288 [Reserved]

§ 63.1289 [Reserved]

Appendix to Subpart HHH—Tables

TABLE 1.—LIST OF HAZARDOUS AIR POLLUTANTS (HAP) FOR SUBPART HHH

CAS Number[a]	Chemical name
75070 ...	Acetaldehyde
71432 ...	Benzene (includes benzene in gasoline)
75150 ...	Carbon disulfide
463581	Carbonyl sulfide
100414	Ethyl benzene
107211	Ethylene glycol
75050 ...	Acetaldehyde
50000 ...	Formaldehyde
110543	n-Hexane
91203 ...	Naphthalene
108883	Toluene
540841	2,2,4-Trimethylpentane
1330207	Xylenes (isomers and mixture)
95476 ...	o-Xylene
108383	m-Xylene
106423	p-Xylene

[a] CAS numbers refer to the Chemical Abstracts Services registry number assigned to specific compounds, isomers, or mixtures of compounds.

TABLE 2 TO SUBPART HHH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.1(a)(1)	Yes	
§ 63.1(a)(2)	Yes	
§ 63.1(a)(3)	Yes	
§ 63.1(a)(4)	Yes	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6) through (a)(8)	Yes	
§ 63.1(a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes	

TABLE 2 TO SUBPART HHH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§63.1(a)(11)	Yes	
§63.1(a)(12) through (a)(14)	Yes	
§63.1(b)(1)	No	Subpart HHH specifies applicability.
§63.1(b)(2)	Yes	
§63.1(b)(3)	No.	
§63.1(c)(1)	No	Subpart HHH specifies applicability.
§63.1(c)(2)	No	
§63.1(c)(3)	No	Section reserved.
§63.1(c)(4)	Yes	
§63.1(c)(5)	Yes	
§63.1(d)	No	Section reserved.
§63.1(e)	Yes	
§63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HHH.
§63.3(a) through (c)	Yes	
§63.4(a)(1) through (a)(3)	Yes	
§63.4(a)(4)	No	Section reserved.
§63.4(a)(5)	Yes	
§63.4(b)	Yes	
§63.4(c)	Yes	
§63.5(a)(1)	Yes	
§63.5(a)(2)	No	Preconstruction review required only for major sources that commence construction after promulgation of the standard.
§63.5(b)(1)	Yes	
§63.5(b)(2)	No	Section reserved.
§63.5(b)(3)	Yes	
§63.5(b)(4)	Yes	
§63.5(b)(5)	Yes	
§63.5(b)(6)	Yes	
§63.5(c)	No	Section reserved.
§63.5(d)(1)	Yes	
§63.5(d)(2)	Yes	
§63.5(d)(3)	Yes	
§63.5(d)(4)	Yes	
§63.5(e)	Yes	
§63.5(f)(1)	Yes	
§63.5(f)(2)	Yes	
§63.6(a)	Yes	
§63.6(b)(1)	Yes	
§63.6(b)(2)	Yes	
§63.6(b)(3)	Yes	
§63.6(b)(4)	Yes	
§63.6(b)(5)	Yes	
§63.6(b)(6)	No	Section reserved.
§63.6(b)(7)	Yes	
§63.6(c)(1)	Yes	
§63.6(c)(2)	Yes	
§63.6(c)(3) and (c)(4)	No	Section reserved.
§63.6(c)(5)	Yes	
§63.6(d)	No	Section reserved.
§63.6(e)	Yes	
§63.6(e)	Yes	Except as otherwise specified.
§63.6(e)(1)(i)	No	Addressed in §63.1272.
§63.6(e)(1)(ii)	Yes	
§63.6(e)(1)(iii)	Yes	
§63.6(e)(2)	Yes	
§63.6(e)(3)(i)	Yes	Except as otherwise specified.
§63.6(e)(3)(i)(A)	No	Addressed by §63.1272(c).
§63.6(e)(3)(i)(B)	Yes	
§63.6(e)(3)(i)(C)	Yes	
§63.6(e)(3)(ii) through (3)(vi)	Yes	
§63.6(e)(3)(vii).		
§63.6(e)(3)(vii) (A)	Yes	
§63.6(e)(3)(vii) (B)	Yes	Except that the plan must provide for operation in compliance with §63.1272(c).
§63.6(e)(3)(vii) (C)	Yes	
§63.6(e)3)(viii)	Yes	
§63.7(e)(1)	Yes	
§63.7(e)(2)	Yes	
§63.7(e)(3)	Yes	
§63.7(e)(4)	Yes	
§63.7(f)	Yes	
§63.7(g)	Yes	
§63.7(h)	Yes	
§63.8(a)(1)	Yes	
§63.8(a)(2)	Yes	
§63.8(a)(3)	No	Section reserved.
§63.8(a)(4)	Yes	
§63.8(b)(1)	Yes	
§63.8(b)(2)	Yes	
§63.8(b)(3)	Yes	

TABLE 2 TO SUBPART HHH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.8(c)(1)	Yes	
§ 63.8(c)(2)	Yes	
§ 63.8(c)(3)	Yes	
§ 63.8(c)(4)	No.	
§ 63.8(c)(5) through (c)(8)	Yes	
§ 63.8(d)	Yes	
§ 63.8(e)	Yes	Subpart HHH does not specifically require continuous emissions monitor performance evaluations, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes	
§ 63.8(f)(6)	No	Subpart HHH does not require continuous emissions monitoring.
§ 63.8(g)	No	Subpart HHH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes	
§ 63.9(b)(1)	Yes	
§ 63.9(b)(2)	Yes	Sources are given 1 year (rather than 120 days) to submit this notification.
§ 63.9(b)(3)	Yes	
§ 63.9(b)(4)	Yes	
§ 63.9(b)(5)	Yes	
§ 63.9(c)	Yes	
§ 63.9(d)	Yes	
§ 63.9(e)	Yes	
§ 63.9(f)	No.	
§ 63.9(g)	Yes	
§ 63.9(h)(1) through (h)(3)	Yes	
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) and (h)(6)	Yes	
§ 63.9(i)	Yes	
§ 63.9(j)	Yes	
§ 63.10(a)	Yes	
§ 63.10(b)(1)	Yes	
§ 63.10(b)(2)	Yes	
§ 63.10(b)(3)	No	
§ 63.10(c)(1)	Yes	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (c)(8)	Yes	
§ 63.10(c)(9)	No	Section reserved.
§ 63.10(c)(10) through (c)(15)	Yes	
§ 63.10(d)(1)	Yes	
§ 63.10(d)(2)	Yes	
§ 63.10(d)(3)	Yes	
§ 63.10(d)(4)	Yes	
§ 63.10(d)(5)	Yes	Subpart HHH requires major sources to submit a startup, shutdown and malfunction report semi-annually.
§ 63.10(e)(1)	Yes	
§ 63.10(e)(2)	Yes	
§ 63.10(e)(3)(i)	Yes	Subpart HHH requires major sources to submit Periodic Reports semi-annually.
§ 63.10(e)(3)(i)(A)	Yes	
§ 63.10(e)(3)(i)(B)	Yes	
§ 63.10(e)(3)(i)(C)	No	Subpart HHH does not require quarterly reporting for excess emissions.
§ 63.10(e)(3)(ii) through (e)(3)(viii)	Yes	
§ 63.10(f)	Yes	
§ 63.11(a) and (b)	Yes	
§ 63.12(a) through (c)	Yes	
§ 63.13(a) through (c)	Yes	
§ 63.14(a) and (b)	Yes	
§ 63.15(a) and (b)	Yes	

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