demonstration pursuant to section 189(a)(1)(B); the reasonably available control measure (RACM) provisions of section 189(a)(1)(C); the reasonable further progress (RFP) provisions of section 189(c); and, the attainment demonstration, RACM, RFP and contingency measure provisions of part D, subpart 1 contained in section 172.

Lastly, EPA finds that our obligation to promulgate a FIP addressing the Paul Spur/Douglas NA attainment-related requirements is suspended for as long as the underlying State obligation is suspended.

This final action does not constitute a redesignation to attainment under CAA section 107(d)(3) because Arizona has not submitted a maintenance plan and EPA has not approved such a plan for the Paul Spur/Douglas NA as meeting the requirements of section 175A of the CAA, nor has EPA determined that Arizona has met the other CAA requirements for redesignation. The classification and designation status in 40 CFR part 81 remains moderate nonattainment for the Paul Spur/Douglas NA until such time as EPA determines that Arizona has met the CAA requirements for redesignating the Paul Spur/Douglas NA to attainment.

IV. Statutory and Executive Order Reviews

With this action, we are making a determination regarding attainment of the PM_{10} NAAQS based on air quality data and, based on this determination, suspending certain Federal requirements. Therefore, this action would not impose additional requirements beyond those imposed by State law or by the CAA. For that reason, this action:

- Is not 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 Clean Air Act; and
- Does not provide EPA with the discretionary authority to address disproportionate human health or environmental effects with practical, appropriate, and legally permissible methods under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this action does not have Tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP obligations discussed herein do not apply to Indian Tribes and thus will not impose substantial direct costs on Tribal governments or preempt Tribal law.

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 action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by October 1, 2012. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (see section 307(b)(2)).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Particulate matter, Reporting and recordkeeping requirements.

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

Dated: July 20, 2012.

Jared Blumenfeld,

Regional Administrator, EPA Region IX.

[FR Doc. 2012–18666 Filed 8–1–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044, FRL 9710–1]

RIN 2060–AR62

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: Notice of Partial Stay

AGENCY: Environmental Protection Agency (EPA).

ACTION: Partial stay of effectiveness of final rule.

SUMMARY: This action stays the effectiveness of national new source emission standards for hazardous air pollutants from coal- and oil-fired electric utility steam generating units issued pursuant to Clean Air Act section 112 that were published in the **Federal Register** on February 16, 2012 (77 FR 9304).

DATES: The effective date of 40 CFR 63.9984(a), 63.10005(g), 63.10030(c), Table 1 to subpart UUUUU of 40 CFR part 63, and row 2 of Table 3 to subpart UUUUU of 40 CFR part 63, published in the **Federal Register** on February 16, 2012 (77 FR 9304), is stayed until November 2, 2012.

FOR FURTHER INFORMATION CONTACT: 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.*

SUPPLEMENTARY INFORMATION:

I. Background

On February 16, 2012, the EPA issued the 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, generally referred to as the mercury and air toxics standards (MATS Rule), which established emissions standards for new and existing coal- and oil-fired electric utility steam generating units. The EPA received petitions, pursuant to section 307(d)(7)(B) of the Clean Air Act, from a number of interested parties requesting reconsideration of certain issues in the rule. On July 20, 2012, the EPA issued a letter, stating its intent to grant the petitions for reconsideration on certain new source issues related to the emission standards issued under Clean Air Act section 112, including measurement issues related to mercury and the data set to which the variability calculation was applied when establishing the new source standards for particulate matter and hydrochloric acid.

The Clean Air Act authorizes the EPA to stay the effectiveness of a rule if the Administrator has convened a proceeding to reconsider the rule. Under section 307(d)(7)(B) of the Act, "The effectiveness of the rule may be stayed during * * * reconsideration * * * by the Administrator or the court for a period not to exceed three months." 42 U.S.C.7607(d)(7)(B). In its letter granting the petitions for reconsideration on certain issues relating to the Clean Air Act section 112 new source standards, the EPA stated that it intended to exercise its authority under section 307(d) to stay the effectiveness of those new source standards for 3 months.

II. Issuance of a Partial Stay Relating to Clean Air Act Section 112(d) New Source Standards

Pursuant to section 307(d)(7)(B) of the Clean Air Act, the EPA hereby stays the effectiveness of 40 CFR 63.9984(a), 63.10005(g), 63.10030(c), Table 1 in subpart UUUUU of 40 CFR part 63, and row 2 of Table 3 in subpart UUUUU of 40 CFR part 63 for 3 months. Thus, by this action, we are staying the effectiveness of these provisions of the rule, published in the **Federal Register** on February 16, 2012 (77 FR 9304). Accordingly, this action also stays the effectiveness of any monitoring, recordkeeping, and reporting requirements related to the section 112(d) new source standards. This stay does not apply to any other provisions of the rule.

This stay of effectiveness will remain in place until November 2, 2012.

List of Subjects in 40 CFR Part 63

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

Dated: July 27, 2012.

Lisa P. Jackson,

Administrator.

[FR Doc. 2012–18871 Filed 8–1–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 300

[EPA–HQ–SFUND–1999–0010; FRL 9704–4]

National Oil and Hazardous Substances Pollution Contingency Plan; National Priorities List: Partial Deletion of the Eastland Woolen Mill Superfund Site

AGENCY: Environmental Protection Agency.

ACTION: Direct final rule.

SUMMARY: The Environmental Protection Agency (EPA) Region 1 is publishing a direct final Notice of Partial Deletion for portions of the Eastland Woolen Mill Superfund Site (Site), located in Corinna, Maine, from the National Priorities List (NPL).

The NPL, promulgated pursuant to section 105 of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980, as amended, is an appendix of the National Oil and Hazardous Substances Pollution Contingency Plan (NCP). This direct final partial deletion is being published by EPA with the concurrence of the State of Maine, through the Maine Department of Environmental Protection, because EPA has determined that all appropriate response actions at these identified parcels under CERCLA, other than five-year reviews, have been completed. However, this partial deletion does not preclude future actions under Superfund.

This partial deletion pertains to all Site media (soil and groundwater) of the properties proposed for deletion.

DATES: This direct final partial deletion is effective October 1, 2012 unless EPA receives adverse comments by September 4, 2012. If adverse comments are received, EPA will publish a timely withdrawal of the direct final partial deletion in the **Federal Register** informing the public that the partial deletion will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID no. EPA–HQ–SFUND–1999–0010, by one of the following methods:

- *http://www.regulations.gov.* Follow on-line instructions for submitting comments.
- *Email: hathaway.ed@epa.gov.*
- *Fax:* 1–617–918–0372.
- *Mail:* Edward Hathaway, U.S. EPA Remedial Project Manager, 5 Post Office Square (OSRR07–1), Boston, MA 02109–3912.
- *Hand delivery:* Edward Hathaway, U.S. EPA Remedial Project Manager, 5 Post Office Square (OSRR07–1), Boston, MA 02109–3912. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID no. EPA–HQ–SFUND–1999–0010. 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 email. 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 email comment directly to EPA without going through *http://www.regulations.gov,* your email 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. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statue. Certain other

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Part II

Environmental Protection Agency

40 CFR Parts 60 and 63

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

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2010–0505; FRL–9665–1]

RIN 2060–AP76

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

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

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

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

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

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

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I. Preamble Acronyms and Abbreviations

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

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

II. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

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

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

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

2. Summary of the Major Provisions of the Regulatory Actions

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

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

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

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

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

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

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

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

3. Costs and Benefits

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

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

[Millions of 2008$] [1]

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

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

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

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

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

B. Does this action apply to me?

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

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Liquid Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather is meant to provide a guide for readers regarding entities likely to be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

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

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

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

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

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

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

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

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

E. Judicial Review

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

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

III. Background Information on the NSPS and NESHAP

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

1. What is the statutory authority for the NSPS?

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

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

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

2. What is the statutory authority for the NESHAP?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B. What is the litigation history?

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

C. What is the sector-based approach?

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

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

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

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

IV. Summary of the Final NSPS Rule

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

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

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

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

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

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

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

1. Standards for Gas Well Affected Facilities

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

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

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

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

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

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

2. Standards for Compressor Affected Facilities

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

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

3. Standards for Pneumatic Controller Affected Facilities

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

4. Standards for Storage Vessels

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

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

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

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

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

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

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

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

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

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

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

A. Gas Well Affected Facilities

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

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

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

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

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

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

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

B. Centrifugal and Reciprocating Compressor Affected Facilities

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

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

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

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

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

C. Pneumatic Controller Affected Facilities

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

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

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

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

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

D. Storage Vessel Affected Facilities

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

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

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

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

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

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

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

F. Changes to Notification, Recordkeeping and Reporting Requirements

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

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

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

VI. Summary of the Final NESHAP Rules

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

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

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

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

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

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

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

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

1. Standards for Small Glycol Dehydration Units

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

2. Standards for Equipment Leaks

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

3. Notification, Recordkeeping and Reporting Requirements

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

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

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

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

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

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

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

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

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

1. Standards for Glycol Dehydration Units

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

2. Notification, Recordkeeping and Reporting Requirements

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4. Other Changes to the Proposed Rule

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4. Other Changes to the Proposed Rule

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

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

VIII. Compliance Related Issues Common to the NSPS and NESHAP

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

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

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

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

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

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

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

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

[9] See footnote 6.

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

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

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

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

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

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

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

1. Notification, Recordkeeping and Reporting Requirements

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

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

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

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

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

NESHAP

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

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

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

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

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

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

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

2. Innovative Compliance Approaches

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

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

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

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

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

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

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

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

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

IX. Summary of Significant NSPS Comments and Responses

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

A. Major Comments Concerning Applicability

1. Activities That Constitute a Modification

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Consistency With the Definition of Modification

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

Physical Change

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

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

Emissions Increase

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

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

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

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

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

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

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

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

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

De Minimis Exception

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

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

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

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

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

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

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

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

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

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

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

Clarifying Changes

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

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

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

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

2. Regulation of Methane and Other Pollutants

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

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

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

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

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

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

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

3. Expanded Scope of the Source Category

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

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

B. Major Comments Concerning Well Completions

1. Applicability and Exemptions

a. Well Exemptions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

c. Definition of Gas Well

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

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

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

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

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

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

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

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

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

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

d. Availability of Infrastructure to Convey Gas to Market

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

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

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

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

e. Fracturing of Wells Using Nitrogen and Carbon Dioxide

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

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

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

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

2. Rule Should Not Prescribe Equipment

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

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

3. Availability of Equipment and Trained Personnel

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

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

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

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

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

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

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

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

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

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

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

TABLE 6—REC UNIT SUPPLY ANALYSIS

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

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

TABLE 6—REC UNIT SUPPLY ANALYSIS—Continued

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

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

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

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

4. Cost and Emissions Calculations

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

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

5. Definition of Affected Facility

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

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

C. Major Comments Concerning Pneumatic Controllers

1. Definition of Affected Facility

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. Controllers in the Transmission and Storage Segment

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

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

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

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

3. Cost and Emissions Calculations

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

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

D. Major Comments Concerning Compressors

1. Compressors in the Transmission and Storage Segment

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

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

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

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

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

2. Dry Seals Versus Wet Seals

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

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

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

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

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

3. New Source Definition

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

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

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

E. Major Comments Concerning Storage Vessels

1. Applicability Threshold Metric

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

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

2. Definition of Affected Facility

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

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

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

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

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

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

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

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

3. References to MACT Standards

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

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

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

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

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

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

4. Availability of Control Equipment

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

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

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

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

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

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

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

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

F. Major Comments Concerning Notification, Recordkeeping and Reporting Requirements

1. 30-Day Notification and Annual Reports

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

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

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

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

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

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

authority no later than 2 days prior to completion.

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

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

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

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

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

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

2. Duplicative Recordkeeping and Reporting Requirements

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

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

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

3. Electronic Reporting of Emissions Data

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

reporting could be structured and implemented.

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

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

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

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

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

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

X. Summary of Significant NESHAP Comments and Responses

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

A. Major Comments Concerning Previously Unregulated Sources

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

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

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

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

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

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

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

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

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

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

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

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

Continued

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

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

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

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

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

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

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

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

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

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

B. Major Comments Concerning the Risk Review

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

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

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

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

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

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

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

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

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

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

C. Major Comments Concerning the Technology Review

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[29] See footnote 25.

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

D. Major Comments Concerning Notification, Recordkeeping and Reporting Requirements

1. Annual Reports

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

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

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

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

2. Electronic Reporting of Emissions Data

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

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

A. What are the air impacts?

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

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

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

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

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

[30] See footnote 25.

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

[32] See footnote 25.

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

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

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

B. What are the energy impacts?

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

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

C. What are the cost impacts?

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

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

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

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

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

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

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

D. What are the economic impacts?

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

E. What are the benefits of this final rule?

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

substantial health effects, welfare effects and climate effects.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

XII. Statutory and Executive Order Reviews

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

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

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

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

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

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

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

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

[Millions of 2008$] [1]

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

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

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

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

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

B. Paperwork Reduction Act

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

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

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

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

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

EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small.

For this reason, we estimate a total of 39 such occurrences for all sources subject to 40 CFR part 63, subpart HH, a total of three such occurrences for all sources subject to 40 CFR part 63, subpart HHH, and a total of 6 such occurrences for all sources subject to 40 CFR part 60, subparts KKK and LLL over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $20.1 million. This includes 384,866 labor hours per year at a total labor cost of $19.5 million per year, and annualized capital costs of $0.36 million, and annual operating and maintenance costs of $0.20 million. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications and recordkeeping. All burden estimates are in 2008 dollars and represent the most cost-effective monitoring approach for affected facilities. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When these ICR are approved by OMB, the agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control numbers for the approved information collection requirements contained in the final rule.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities (SISNOSE). Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) A small business as defined by NAICS codes 211111, 211112, 221210, 486110 and 486210; whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

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

Based upon the analysis in the RIA, which is in the Docket, when revenue from additional natural gas product recovered is not included, we estimate that 123 of the 127 small firms analyzed (97 percent) are likely to have impacts less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. However, when revenue from additional natural gas product recovery is included, we estimate that none of the analyzed firms will have an impact greater than 1 percent.

For the final NESHAP amendments, we estimate that 11 of the 35 firms (31 percent) that own potentially affected facilities are small entities. The EPA performed an analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, none are likely to have impacts greater than 1 percent in terms of the ratio of annualized compliance costs to revenues.

After considering the economic impact of the combined NSPS and NESHAP amendments on small entities, I certify this action will not have a significant impact on a substantial number of small entities (SISNOSE). While both the NSPS and NESHAP amendment would individually result in a no SISNOSE finding, the EPA performed an additional analysis in order to certify the rule in its entirety. This analysis compared compliance costs to entity revenues for the total of all the entities affected by the NESHAP amendments and the sample of entities analyzed for the NSPS. When revenues from additional natural gas product sales are not included, 132 of the 136 small firms (97 percent) in the sample are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. When revenues from additional natural gas product sales are included, none of the 136 small firms (100 percent) are likely to have impacts greater than 1 percent.

Our determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact

on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to REC activities occur without a significant time lag between implementing the control and obtaining the recovered product, unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions occur over a short span of time, during which the additional product recovery is also accomplished and payments for recovered products are settled.

Although this final rule will not impact a substantial number of small entities, the EPA, nonetheless, has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

D. Unfunded Mandates Reform Act

This final action does not contain a federal mandate under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for state, local, and tribal governments, in the aggregate, or to the private sector. The action would not result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any 1 year. Thus, this final rule is not subject to the requirements of sections 202 or 205 of UMRA.

This final rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments nor does it impose obligations upon them.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. These final rules primarily affect private industry, and do not impose significant economic costs on state or local governments. On the contrary, we believe the modification provisions discussed in section IX.A for well completions conducted at gas wells constructed on or before August 23, 2011, will reduce permitting burden borne by the States. These provisions will result in fewer sources becoming affected facilities under the NSPS while achieving emission reductions beginning October 15, 2012 equal to those achieved by new sources beginning January 1, 2015. Thus, Executive Order 13132 does not apply to this action.

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

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

The EPA has concluded that this action will not have tribal implications because it doesn't impose a significant cost to the tribal government. However, there are significant tribal interests because of the growth of the oil and gas production industry in Indian country.

The EPA initiated a consultation process with tribal officials early in the process of developing this regulation to permit them to have meaningful and timely input into its development. During the consultation process, the EPA conducted outreach and information meetings prior to the proposal in 2010. The EPA met with the Inter Tribal Environmental Council, which include many of the Region VI tribes, The Tribal leadership summit in Region X, and Tribal Energy Conference hosted by Ft. Belknap, and the National Tribal Forum.

After the proposal was published, letters were sent to all tribal leaders offering to consult on a government-to-government basis on the rule. As part of the consultation process and in response to these letters, an outreach call was held on October 12, 2011. Tribes that participated on this call were: Fond du Lac Band of Lake Superior Chippewa, Fort Belknap Indian Community, Forest County Potawatomi Community, Southern Ute Indian Tribe, and Pueblo of Santa Clara.

In this meeting the tribes were presented the information in the proposal. The tribes asked general clarifying questions but did not provide specific comments. Comments on the proposal were received from an affiliate of the Southern Ute Indian Tribe. The commenter expressed concern about the impacts of the rule on natural gas and oil production operations on the Southern Ute Indian reservation and requested additional time to evaluate the impacts. In response to this and other requests, the comment period was extended. More specific comments can be found in the docket.

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

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This action would not relax the control measures on existing regulated sources. The EPA's risk assessments (included in the docket for this final rule) demonstrate that the existing regulations are associated with an acceptable level of risk and provide an ample margin of safety to protect public health.

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

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. These final rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The final NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the final NESHAP amendments are not "significant energy actions" as defined in Executive Order 13211, (66 FR 28355, May 22, 2001). The final NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the final NSPS is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001).

The basis for these determinations is as follows. Emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the final NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the final rules.

We use the NEMS to estimate the impacts of the combined final rules on

the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

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

The analysis of energy system impacts for the final NSPS under the primary baseline shows that domestic natural gas production is not likely to change in 2015, the year used in the RIA to analyze impacts. Average natural gas prices are also not estimated to change in response to the final rules. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.01/barrel or about 0.01 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars. The NEMS-based analysis estimates in the year of analysis, 2015, that net imports of natural gas and crude oil will not change.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

For more information on the estimated energy effects, please refer to the economic impact analysis for this final rule. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

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

This final rulemaking involves technical standards. Three VCS were identified as applicable for the purpose of these rules. The VCS ASTM D6522–00 (2005), *Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions From Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers,* is an acceptable alternative to EPA Methods 3A and 10 for identifying nitrogen oxides, carbon monoxide, and oxygen concentrations when the fuel is natural gas. The VCS ASTM D6420–99 (2004), *Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry,* is an acceptable alternative to EPA Method 18. The VCS ANSI/ASME PTC 19.10–1981 (Part 10, Instruments and Apparatus), *Flue and Exhaust Gas Analyses* is an acceptable alternative to EPA Methods 3B and 16A manual portion only, not the instrumental portion.

No potential VCS were identified for EPA Methods 1A, 2A, 2D, 21, and 22.

During the search, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that were similar to the EPA's reference method, the EPA ordered a copy of the standard and reviewed it as a potential equivalent method. All potential standards were reviewed to determine the practicality of the VCS for this action. This review requires significant method validation data that meet the requirements of EPA Method 301 for accepting alternative methods or scientific, engineering and policy equivalence to procedures in the EPA reference methods. The EPA may reconsider determinations of impracticality when additional information is available for particular VCS.

The search identified 18 other VCS that were potentially applicable for these rules in lieu of the EPA reference methods. After reviewing the available standards, the EPA determined that 18 candidate VCS (ASTM D3154–00 (2006), ASTM D3464–96 (2007), ASTM D3796–90 (2004), ISO 10780:1994, ASME B133.9–1994 (2001), ANSI/ASME PTC 19.10–1981 Part 10, ASTM D5835–95 (2007), ISO 10396:1993, ISO 12039:2001, ASTM D6522–00 (2005), CAN/CSA Z223.2–M86 (1999), CAN/CSA Z223.21–M1978, ASTM D3162–94 (2005), ASTM D4323–84 (2009), ASTM D6060–96 (2001), ISO 14965:2000(E), EN 12619 (1999), ASTM D4855–97 (2002)) identified for measuring emissions of pollutants or their surrogates subject to emission standards in the rules would not be practical due to lack of equivalency, documentation, validation data and other important technical and policy considerations. Refer to the memorandum in the docket for further details on the EPA's review of these VCS.

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

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

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

human health or environmental effects on any population, including any minority, low-income, or indigenous populations.

To examine the potential for any environmental justice issues that might be associated with each source category, we evaluated the percentages of various social, demographic, and economic groups within the at-risk population living near the facilities where these source categories are located and compared them to national averages. The development of demographic analyses to inform the consideration of environmental justice issues in the EPA rulemakings is an evolving science.

The EPA conducted a demographic analysis, focusing on populations within 50 km of any facility in each of the source categories that are estimated to have HAP exposures which result in cancer risks of 1-in-1 million or greater or non-cancer hazard indices of 1 or greater based on estimates of current HAP emissions. The results of this analysis are documented in the technical report: *Risk and Technology Review—Analysis of Socio-Economic Factors for Populations Living Near Oil & Natural Gas Production Facilities,* located in the docket for this rulemaking.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health. Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic non-cancer health impacts are unlikely. The EPA has determined that, although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

To promote meaningful involvement, the EPA conducted three public hearings on the proposal. The hearings were held in Pittsburgh, Pennsylvania, on September 27, 2011, Denver, Colorado, on September 28, 2011, and Arlington, Texas, on September 29, 2011. A total of 261 people spoke at the three hearings and 735 people attended the hearings. The attendees at the hearings included private citizens, community-based and environmental organizations, industry representatives, associations representing industry and local and state government officials.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). The final rules will be effective on October 15, 2012.

List of Subjects

40 CFR Part 60

Environmental protection, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements, Volatile organic compounds.

40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Incorporation by reference, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: April 17, 2012.

Lisa P. Jackson,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 60—[AMENDED]

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

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

■ 2. Section 60.17 is amended by:
■ a. Revising paragraph (a) introductory text, (a)(7), (a)(86), (a)(91), and (a)(92);
■ b. Adding paragraphs (a)(95), (a)(96), (a)(97), and (a)(98); and
■ c. Revising paragraph (h) introductory text and (h)(4) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, Telephone (610) 832–9585, and are also available at the following Web site: *http://www.astm.org;* or ProQuest, 789 East Eisenhower Parkway, Ann Arbor, MI 48106–1346, Telephone (734) 761–4700, and are also available at the following Web site: *http://www.proquest.com.*

* * * * *

(7) ASTM D86–96, Standard Test Method for Distillation of Petroleum Products (Approved April 10, 1996), IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h) and 60.5401(f).

* * * * *

(86) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers (Approved October 1, 2005), IBR approved for table 2 of subpart JJJJ of this part, and §§ 60.5413(b) and (d).

* * * * *

(91) ASTM E169–93, Standard Practices for General Techniques of Ultraviolet-Visible Quantitative Analysis (Approved May 15, 1993), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f) and 60.5400(f).

(92) ASTM E260–96, Standard Practice for Packed Column Gas Chromatography (Approved April 10, 1996), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f) and 60.5406(b).

* * * * *

(95) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (Approved May 10, 2003), IBR approved for § 60.5413(d).

(96) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (Approved June 1, 2006), IBR approved for § 60.5413(d).

(97) ASTM D1945–03 (Reapproved 2010), Standard Test Method for Analysis of Natural Gas by Gas Chromatography (Approved January 1, 2010), IBR approved for § 60.5413(d).

(98) ASTM D5504–08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence (Approved June 15, 2008), IBR approved for § 60.5413(d).

* * * * *

(h) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990, Telephone (800) 843–2763, and are also available at the following Web site: *http://www.asme.org.*

* * * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus] (Issued August 31, 1981), IBR approved for §§ 60.56c(b), 60.63(f), 60.106(e), 60.104a(d), (h), (i) and (j), 60.105a(d), (f) and (g), 60.106a(a), 60.107a(a), (c) and (d), tables 1 and 3 of subpart EEEE, tables 2 and 4 of subpart FFFF, table 2 of subpart JJJJ, §§ 60.4415(a), 60.2145(s) and (t), 60.2710(s), (t) and (w), 60.2730(q), 60.4900(b) and 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§ 60.5406(c) and 60.5413(b).

* * * * *

Subpart KKK—Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

■ 3. The heading for Subpart KKK is revised to read as set forth above.

■ 4. Section 60.630 is amended by revising paragraph (b) to read as follows:

§ 60.630 Applicability and designation of affected facility.

* * * * *

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 20, 1984, and on or before August 23, 2011, is subject to the requirements of this subpart.

* * * * *

Subpart LLL—Standards of Performance for SO_2 Emissions From Onshore Natural Gas Processing for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

■ 5. The heading for Subpart LLL is revised to read as set forth above.

■ 6. Section 60.640 is amended by revising paragraph (d) to read as follows:

§ 60.640 Applicability and designation of affected facilities.

* * * * *

(d) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section which commences construction or modification after January 20, 1984, and on or before August 23, 2011.

* * * * *

■ 7. Add subpart OOOO, consisting of 60.5360 through 60.5430, to part 60 to read as follows:

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution

Sec.

60.5360 What is the purpose of this subpart?
60.5365 Am I subject to this subpart?
60.5370 When must I comply with this subpart?
60.5375 What standards apply to gas well affected facilities?
60.5380 What standards apply to centrifugal compressor affected facilities?
60.5385 What standards apply to reciprocating compressor affected facilities?
60.5390 What standards apply to pneumatic controller affected facilities?
60.5395 What standards apply to storage vessel affected facilities?
60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?
60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?
60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?
60.5405 What standards apply to sweetening units at onshore natural gas processing plants?
60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?
60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?
60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?
60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?
60.5411 What additional requirements must I meet to determine initial compliance for my closed vent systems routing emissions from storage vessels or centrifugal compressor wet seal fluid degassing systems?
60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?
60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?
60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?
60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel or centrifugal compressor affected facility?
60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?
60.5420 What are my notification, reporting, and recordkeeping requirements?
60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
60.5425 What parts of the General Provisions apply to me?
60.5430 What definitions apply to this subpart?
Table 1 to Subpart OOOO of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)
Table 2 to Subpart OOOO of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)
Table 3 to Subpart OOOO of Part 60—Applicability of General Provisions to Subpart OOOO

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution

§ 60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commence construction, modification or reconstruction after August 23, 2011.

§ 60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section for which you commence construction, modification or reconstruction after August 23, 2011.

(a) Each gas well affected facility, which is a single natural gas well.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals that is located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d)(1) For the oil production segment (between the wellhead and the point of custody transfer to an oil pipeline), each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) For the natural gas production segment (between the wellhead and the point of custody transfer to the natural gas transmission and storage segment and not including natural gas processing plants), each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(3) For natural gas processing plants, each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel, located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment.

(f) The group of all equipment, except compressors, within a process unit is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423(c) but are not required to comply with §§ 60.5405 through 60.5407 and §§ 60.5410(g) and 60.5415(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405 through 60.5407, 60.5410(g), 60.5415(g), and 60.5423 of this subpart.

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

(1) A gas well facility that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of § 60.5375 are met. For purposes of this provision, the dates specified in § 60.5375(a) do not apply, and such facilities, as of October 15, 2012, must meet the requirements of § 60.5375(a)(1) through (4).

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

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

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

§ 60.5370 When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than October 15, 2012 or upon startup, whichever is later.

(b) The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

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

§ 60.5375 What standards apply to gas well affected facilities?

If you are the owner or operator of a gas well affected facility, you must comply with paragraphs (a) through (f) of this section.

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing begun prior to January 1, 2015, you must comply with the requirements of paragraphs (a)(3) and (4) of this section unless a more stringent state or local emission control requirement is applicable; optionally, you may comply with the requirements of paragraphs (a)(1) through (4) of this section. For each new well completion operation with hydraulic fracturing begun on or after January 1, 2015, you must comply with the requirements in paragraphs (a)(1) through (4) of this section.

(1) For the duration of flowback, route the recovered liquids into one or more storage vessels or re-inject the recovered liquids into the well or another well, and route the recovered gas into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere. If this is infeasible, follow the requirements in paragraph (a)(3) of this section.

(2) All salable quality gas must be routed to the gas flow line as soon as

practicable. In cases where flowback emissions cannot be directed to the flow line, you must follow the requirements in paragraph (a)(3) of this section.

(3) You must capture and direct flowback emissions to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each gas well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in § 60.5420(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to gas well affected facilities as required by § 60.5410.

(d) You must demonstrate continuous compliance with the standards that apply to gas well affected facilities as required by § 60.5415.

(e) You must perform the required notification, recordkeeping and reporting as required by § 60.5420.

(f)(1) For each gas well affected facility specified in paragraphs (f)(1)(i) and (ii) of this section, you must comply with the requirements of paragraphs (f)(2) and (3) of this section.

(i) Each well completion operation with hydraulic fracturing at a gas well affected facility meeting the criteria for a wildcat or delineation well.

(ii) Each well completion operation with hydraulic fracturing at a gas well affected facility meeting the criteria for a non-wildcat low pressure gas well or non-delineation low pressure gas well.

(2) You must capture and direct flowback emissions to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback. You must also comply with paragraphs (a)(4) and (b) through (e) of this section.

(3) You must maintain records specified in § 60.5420(c)(1)(iii) for wildcat, delineation and low pressure gas wells.

§ 60.5380 What standards apply to centrifugal compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5385 What standards apply to reciprocating compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section.

(1) Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b) or (c) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b) or (c) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet per hour is required based on functional needs, including but not limited to response time, safety and positive actuation.

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in § 60.5420(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013 at a location between the wellhead and a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location between the wellhead and a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415.

(f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420, except that you are not required to submit the notifications specified in § 60.5420(a).

§ 60.5395 What standards apply to storage vessel affected facilities?

Except as provided in paragraph (d) of this section, you must comply with the standards in this section no later than October 15, 2013 for each storage vessel

affected facility constructed, modified or reconstructed after August 23, 2011, with VOC emissions equal to or greater than 6 tpy, as determined in paragraph (a) of this section.

(a) *Emissions determination*—(1) *Well sites with no other wells in production.* For each storage vessel constructed, modified or reconstructed at a well site with no other wells in production, you must determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology within 30 days after startup, and minimize emissions to the extent practicable during the 30-day period using good engineering practices. For each storage vessel affected facility emitting more than 6 tpy VOC, you must reduce VOC emissions by 95.0 percent or greater within 60 days after startup.

(2) *Well sites with one or more wells already in production.* For each storage vessel constructed, modified or reconstructed at a well site with one or more wells already in production, you must determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology upon startup. For each storage vessel affected facility emitting more than 6 tpy VOC, you must reduce VOC emissions by 95.0 percent or greater upon startup.

(b) *Control requirements.* (1) If you use a control device (such as an enclosed combustion device or vapor recovery device) to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) *Compliance, notification, recordkeeping, and reporting.* (1) You must demonstrate initial compliance with standards that apply to storage vessel affected facilities as required by § 60.5410.

(2) You must demonstrate continuous compliance with standards that apply to storage vessel affected facilities as required by § 60.5415.

(3) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

(d) *Exemptions.* This section does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, or 40 CFR part 63, subparts G, CC, HH, WW, or HHH.

§ 60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§ 60.482–1a(a), (b), and (d), 60.482–2a, and 60.482–4a through 60.482–11a, except as provided in § 60.5401.

(b) You may elect to comply with the requirements of §§ 60.483–1a and 60.483–2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402 of this subpart.

(d) You must comply with the provisions of § 60.485a of this part except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a of this part except as provided in §§ 60.5401, 60.5421, and 60.5422 of this part.

(f) You must use the following provision instead of § 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–93, E168–92, or E260–96 (incorporated by reference as specified in § 60.17) must be used.

§ 60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of § 60.5400(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in § 60.5400(c) and in paragraph (b)(4) of this section, and § 60.482–4a(a) through (c) of subpart VVa.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482–4a(b)(1) of subpart VVa.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482–5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1) and 60.482–7a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86–96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method

D86–96 (incorporated by reference as specified in § 60.17).

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/ divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/ divided by 100) may be re-monitored.

§ 60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

§ 60.5405 What standards apply to sweetening units at onshore natural gas processing plants?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in § 60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in paragraph § 60.8(b).

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:

X = average sulfur feed rate, Mg/D (LT/D).

Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).

= 1.331×10^{-3}Mg/dscm, for metric units.

= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).

= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408 or a chromatographic procedure following ASTM E260–96 (incorporated by reference as specified in § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in § 60.5405(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)\frac{\square}{S + E}$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = \frac{C_e Q_{sd}}{K_1}$$

Where:

E = emission rate of sulfur per run, kg/hr.

C_e = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A to part 60 of this chapter to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in.) from the wall.

(i) You must use Method 6 of appendix A to part 60 of this chapter to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent.

(ii) You must use Method 15 of appendix A to part 60 of this chapter to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A or Method 15 of appendix A to part 60 of this chapter or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A to part 60 of this chapter to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of § 60.5405(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) *The accumulation of sulfur product over each 24-hour period.* The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) *The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period.* At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) *The average acid gas flow rate from the sweetening unit.* You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) *The sulfur feed rate (X).* For each 24-hour period, you must compute X using the equation specified in § 60.5406(b)(1).

(5) *The required sulfur dioxide emission reduction efficiency for the 24-hour period.* You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) *A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere.* The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent

performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B to part 60 of this chapter must apply, and Method 6 must be used for systems required by paragraph (b) of this section.

§ 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A–80–20–A, Entry II–I–67).

(a) When an instantaneous sample is desired and H_2S concentration is ten grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than ten grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml=0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine thru (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then, Grains H_2S per 100 cubic foot of gas = 100(D–C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

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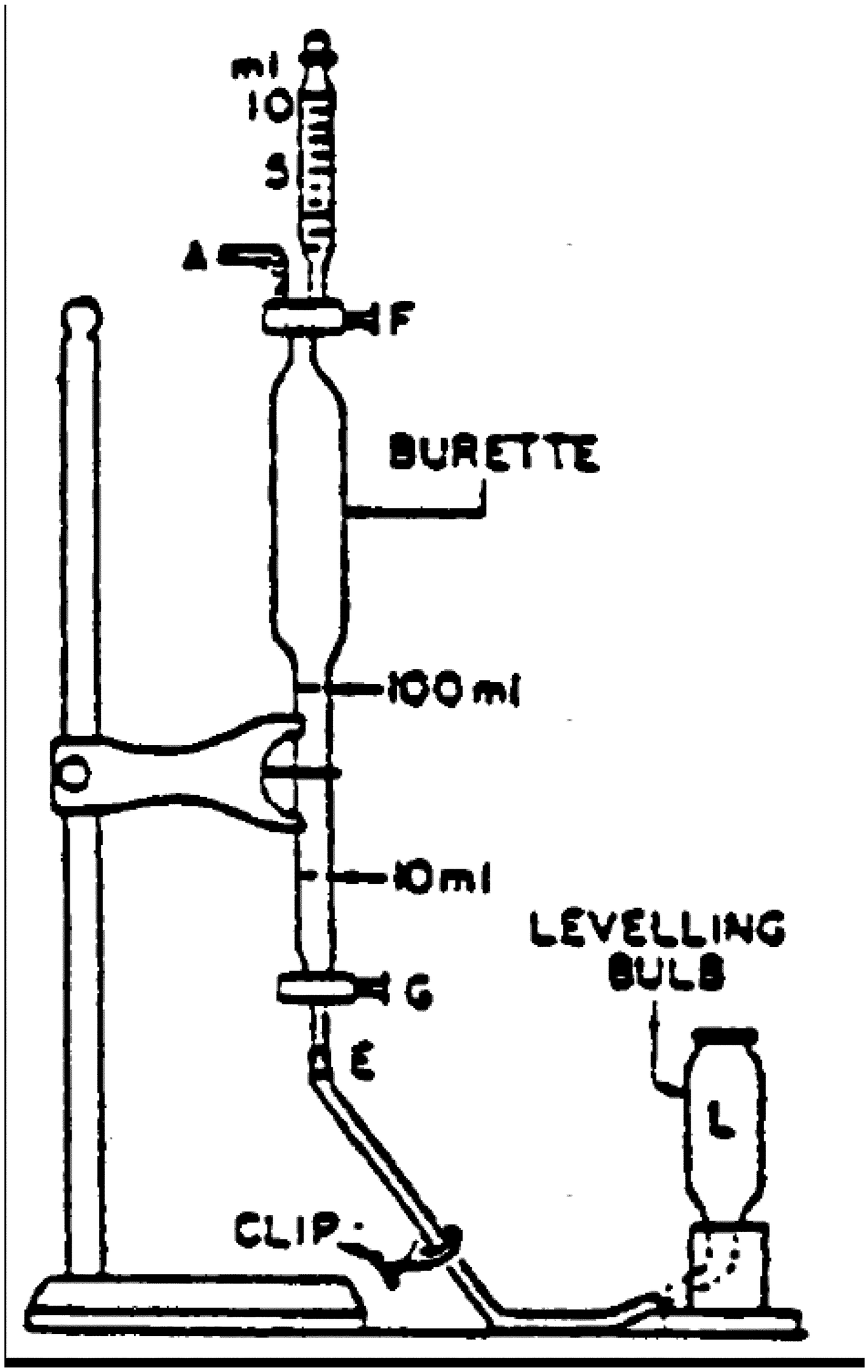

Figure 1. Tutwiler burette (lettered items mentioned in text).

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§ 60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (g) of this section. The initial compliance period begins on October 15, 2012 or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for your affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the standards for each well completion operation conducted at your gas well affected facility you must comply with paragraphs (a)(1) through (a)(4) of this section.

(1) You must submit the notification required in § 60.5420(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in § 60.5420(b).

(3) You must maintain a log of records as specified in § 60.5420(c)(1) for each well completion operation conducted during the initial compliance period.

(4) For each gas well affected facility subject to both § 60.5375(a)(1) and (3), you must maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by § 60.5380 and as demonstrated by the requirements of § 60.5413.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412.

(3) You must conduct an initial performance test as required in § 60.5413 within 180 days after initial startup or by October 15, 2012, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415(b).

(4) You must conduct the initial inspections required in § 60.5416.

(5) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417.

(6) You must submit the notifications required in 60.7(a)(1), (3), and (4).

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420(b) for each centrifugal compressor affected facility

(8) You must maintain the records as specified in § 60.5420(c)(3).

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) During the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) You must submit the notifications required in 60.7(a)(1), (3), and (4).

(3) You must submit the initial annual report for your reciprocating compressor as required in § 60.5420(b).

(4) You must maintain the records as specified in § 60.5420(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with emission standards for your pneumatic controller affected facility you comply with the requirements specified in paragraphs (d)(1) through (6) of this section.

(1) If applicable, you have demonstrated by maintaining records as specified in § 60.5420(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in § 60.5390(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven other than by use of natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of § 60.5390(b)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of § 60.5420(b).

(6) You must maintain the records as specified in § 60.5420(c)(4) for each pneumatic controller affected facility.

(e) To achieve initial compliance with the emission standards for your storage vessel affected facility you must comply with paragraphs (e)(1) through (9) of this section.

(1) You have determined the VOC emission rate within 30 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, and you must use good engineering practices to minimize emissions during the 30-day period.

(2) You must determine the VOC emission rate upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(3) For storage vessel affected facilities emitting more than 6 tpy VOC, you must reduce VOC emissions by 95.0 percent or greater within 60 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(4) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412 within 60 days after startup for storage vessels constructed, modified

or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(5) You must conduct an initial performance test as required in § 60.5413 within 180 days after initial startup or within 180 days of October 15, 2013, whichever is later, and must conduct the compliance demonstration in § 60.5415(b).

(6) You must conduct the initial inspections required in § 60.5416.

(7) You must install and operate continuous parameter monitoring systems in accordance with § 60.5417.

(8) You must submit the information in paragraphs (e)(1) through (7) of this section in the initial annual report as required in § 60.5420(b).

(9) You must maintain the records as specified in § 60.5420(c)(5) for each storage vessel affected facility.

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in § 60.5405(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

§ 60.5411 What additional requirements must I meet to determine initial compliance for my closed vent systems routing materials from storage vessels and centrifugal compressor wet seal degassing systems?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your storage vessel or centrifugal compressor affected facility.

(a) *Closed vent system requirements.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel or wet seal fluid degassing system to a control device that meets the requirements specified in § 60.5412.

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by § 60.5416(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere that is capable of taking periodic readings as specified in § 60.5416(a)(4) and sounds an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device to the atmosphere.

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) *Cover requirements.* (1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, and gauge wells) shall form a continuous barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system to a control device designed and operated in accordance with the requirements of paragraph (a) of this section.

§ 60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your storage vessel or centrifugal compressor affected facility.

(a) If you use a control device to meet the emission reduction standard in § 60.5380(a)(1) for your centrifugal compressor or § 60.5395(a)(1) or (2) for your storage vessel, you must use one of the control devices specified in paragraphs (a)(1) through (3) of this section. You must demonstrate that the control device achieves the performance requirements using the performance test methods and procedures specified in § 60.5413.

(1) You must design and operate an enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413.

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413.

(iii) You must operate at a minimum temperature of 760 °C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 60.5413.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) You must design and operate a vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413. The vapor recovery device must meet the design analysis requirements of § 60.5413(c).

(3) You must design and operate a flare in accordance with the requirements of § 60.5413.

(b) You must operate each control device in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility, as required under § 60.5395, or wet seal fluid degassing system affected facility, as required under § 60.5380, through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of § 60.5417, you must demonstrate compliance according to the requirements of § 60.5415(e)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413(c)(2) or (3) for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in § 60.5420(c)(6).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vii) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(iii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 60 or this part.

(iv) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(v) Burn the spent carbon in a hazardous waste incinerator which you have designed and operated in accordance with the requirements of 40 CFR part 265, subpart O.

(vi) Burn the spent carbon in a boiler or industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vii) Burn the spent carbon in a boiler or industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

§ 60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your storage vessel or centrifugal compressor affected facility. You must demonstrate that a control device achieves the performance requirements of § 60.5412(a) using the performance test methods and procedures specified in paragraph (b) of this section. For condensers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with § 60.18(b). You must conduct the compliance determination using Method 22 at 40 CFR part 60, appendix A–7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(5) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(6) A performance test is waived in accordance with § 60.8(b).

(7) A control device that can be demonstrated to meet the performance requirements of § 60.5412(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of § 60.5412(a). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section.

(1) You must use Method 1 or 1A at 40 CFR part 60, appendix A–1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device, and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement specified in § 60.5412(a)(1)(i) or (a)(2).

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device total TOC concentration limit specified in § 60.5412(a)(1)(ii).

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D at 40 CFR part 60, appendix A–2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in § 60.5412(a)(1)(i) or (a)(2), you must use Method 25A at 40 CFR part 60, appendix A–7. You must use the procedures in paragraphs (b)(3)(i)

through (iv) of this section to calculate percent reduction efficiency.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must compute the mass rate of TOC (minus methane and ethane) using the equations and procedures specified in paragraphs (b)(3)(ii)(A) and (B) of this section.

(A) You must use the following equations:

$$E_i = K_2\left(\sum_{j=1}^{n} C_{ij}M_{ij}\right)Q_i$$

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj}M_{oj}\right)Q_o$$

Where:

E_i, E_o = Mass rate of TOC (minus methane and ethane) at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °C.

C_{ij}, C_{oj} = Concentration of sample component j of the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_{ij}, M_{oj} = Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

n = Number of components in sample.

(B) When calculating the TOC mass rate, you must sum all organic compounds (minus methane and ethane) measured by Method 25A at 40 CFR part 60, appendix A–7 using the equations in paragraph (b)(3)(ii)(A) of this section.

(iii) You must calculate the percent reduction in TOC (minus methane and ethane) as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) at the inlet to the control device as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour or kilograms HAP per hour.

E_o = Mass rate of TOC (minus methane and ethane) at the outlet of the control device, as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour per hour.

(iv) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.

(4) You must use Method 25A at 40 CFR part 60, appendix A–7 to measure TOC (minus methane and ethane) to determine compliance with the enclosed combustion device total VOC concentration limit specified in § 60.5412(a)(1)(ii). You must calculate parts per million by volume concentration and correct to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must calculate the TOC concentration for each run as follows:

$$C_{TOC} = \sum_{i=1}^{x} \frac{\left(\sum_{j=i}^{n} C_{ji}\right)}{x}$$

Where:

C_{TOC} = Concentration of total organic compounds minus methane and ethane, dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(iii) You must correct the TOC concentration to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B at 40 CFR part 60, appendix A, ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m\left(\frac{17.9}{20.9 - \%O_{2d}}\right)$$

Where:

C_c = TOC concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_m = TOC concentration, dry basis, parts per million by volume.

$\%O_{2d}$ = Concentration of oxygen, dry basis, percent by volume.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in § 60.5420(b)(7).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in § 60.5420(b)(7). Combustion control devices meeting the criteria in either paragraph (b)(5)(ii)(A) or (B) of this section are not required to conduct periodic performance tests.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section.

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in § 60.5412(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level.

(c) *Control device design analysis to meet the requirements of § 60.5412(a).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design

average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* The manufacturer must demonstrate that a specific model of combustion control device achieves the performance requirements in paragraph (d)(1) of this section by conducting a performance test as specified in paragraphs (d)(2) through (8) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraphs (d)(9) of this section.

(1) The manufacturer must meet the performance test criteria in paragraphs (d)(1)(i) through (iii) of this section.

(i) The control device model tested must meet the emission levels in paragraphs (d)(1)(i)(A) through (C) of this section.

(A) Method 22 at 40 CFR part 60, appendix A–7, results under paragraph (d)(6)(iv) of this section with no indication of visible emissions.

(B) Average Method 25A at 40 CFR part 60, appendix A–7, results under paragraph (d)(8) of this section equal to or less than 10.0 parts per million by volume-wet THC as propane corrected to 3.0 percent carbon dioxide, and

(C) Average carbon monoxide emissions determined under paragraph (d)(6)(iii) of this section equal to or less than 10 parts per million by volume-dry, corrected to 3.0 percent carbon dioxide.

(ii) The manufacturer must determine a maximum inlet gas flow rate, which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(1)(i) of this section.

(iii) A control device meeting the emission levels in paragraph (d)(1)(i)(A) through (C) of this section must demonstrate a minimum destruction efficiency of 95.0 percent for VOC regulated under this subpart.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. The manufacturer must use propene (propylene) gas for the testing fuel. An independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier) must perform all fuel analyses.

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. Within the first 5 minutes, ramp up the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. Within the first 5 minutes, ramp up the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. Within the first 5 minutes, ramp up the firing rate to 100 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) The manufacturer must test all models employing multiple enclosures simultaneously and with all burners operational. The manufacturer must report results for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. The manufacturer must submit data with the test report in accordance with paragraph (d)(9) of this section.

(4) The manufacturer must conduct inlet testing as specified in paragraphs (d)(4)(i) through (iii) of this section.

(i) The fuel flow metering system must be located in accordance with Method 2A at 40 CFR part 60, appendix A–1, (or other approved procedure) to measure fuel flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet fuel flow monitoring meter.

(ii) The manufacturer must determine the inlet flow rate using Method 2A at 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) The manufacturer must conduct inlet fuel sampling in accordance with the criteria in paragraph (d)(5) of this section.

(5) The manufacturer must conduct inlet fuel sampling as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet fuel sampling location, the manufacturer must securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 1 hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of the total hydrocarbon test, and close the canister at the end of the total hydrocarbon test.

(B) Fill one canister for each total hydrocarbon test run.

(C) Label the canisters individually and record on a chain of custody form.

(ii) The manufacturer must analyze each fuel sample using the methods in paragraphs (d)(5)(ii)(A) through (D) of this section. You must include the results in the test report in paragraph (d)(9) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 60.17).

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 60.17).

(C) Carbonyl sulfide, carbon disulfide plus mercaptans using ASTM D5504–08 (incorporated by reference as specified in § 60.17).

(D) Higher heating value using ASTM D3588–98 (Reapproved 2003) or ASTM D4891–89 (Reapproved 2006) (incorporated by reference as specified in § 60.17).

(6) The manufacturer must conduct outlet testing in accordance with the criteria in paragraphs (d)(6)(i) through (iv) and (d)(7) of this section.

(i) The manufacturer must sample and measure flowrate in accordance with the following:

(A) The manufacturer must position the outlet sampling location a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) The manufacturer must measure flow rate using Method 1 at 40 CFR part 60, appendix A–1 for determining flow measurement traverse point location, and Method 2 at 40 CFR part 60, appendix A–1 for measuring duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) The manufacturer must determine molecular weight as specified in paragraph (d)(7) of this section.

(iii) The manufacturer must determine carbon monoxide using Method 10 at 40 CFR part 60, appendix A–4 or ASTM D6522–00 (Reapproved 2005) (incorporated by reference as specified in § 60.17). The manufacturer must run the test at the same time and with the sample points used for the Method 25A at 40 CFR part 60, appendix A–7, testing. An instrument range of 0–10 parts per million by volume-dry (ppmvd) must be used.

(iv) The manufacturer must determine visible emissions using Method 22 at 40 CFR part 60, appendix A–7. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(7) The manufacturer must determine molecular weight as specified in paragraphs (d)(7)(i) and (ii) of this section.

(i) The manufacturer must collect an integrated bag sample during the Method 4 at 40 CFR part 60, appendix A–3, moisture test. The manufacturer must analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(A) through (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag.

(C) Knead or otherwise vigorously mix the bag contents prior to the gas chromatograph analysis.

(D) Modify the gas chromatograph-thermal conductivity detector calibration procedure in Method 3C at 40 CFR part 60, appendix A–2 by using EPA Alt–045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) The manufacturer must report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen and include in the test report submitted under § 60.5420(b)(7). The manufacturer must determine moisture using Method 4 at 40 CFR part 60, appendix A–3. Traverse both ports with the Method 4 at 40 CFR part 60, appendix A–3, sampling train during each test run. The manufacturer must not introduce ambient air into the Method 3C at 40 CFR part 60, appendix A–2, integrated bag sample during the port change.

(8) The manufacturer must determine total hydrocarbons as specified by the criteria in paragraphs (d)(8)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A at 40 CFR part 60, appendix A–7, except the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during the testing.

(ii) A valid test must consist of three Method 25A at 40 CFR part 60, appendix A–7, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, as amended August 25, 1999, EPA–600/R–97/121.

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C at 40 CFR part 60, appendix A–2.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(9) For each combustion control device model tested by the manufacturer under this section, you must maintain records of the information listed in paragraphs (d)(9)(i) through (vi) of this section.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The design net heating value (minimum and maximum) of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (d)(9)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) You must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated

with test times and calibration values in the test report.

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

(a) For each gas well affected facility, you must demonstrate continuous compliance by submitting the reports required by § 60.5420(b) and maintaining the records for each completion operation specified in § 60.5420(c)(1).

(b) For each centrifugal compressor affected facility, you must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must demonstrate continuous compliance according to paragraph (e)(2) of this section.

(3) You must submit the annual report required by 60.5420(b) and maintain the records as specified in § 60.5420(c)(2).

(c) For each reciprocating compressor affected facility, you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual report as required in § 60.5420(b) and maintain records as required in § 60.5420(c)(3).

(3) You must replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in § 60.5390(a), (b), or (c).

(2) You must submit the annual report as required in § 60.5420(b).

(3) You must maintain records as required in § 60.5420(c)(4).

(e) For each storage vessel affected facility for which the VOC emissions are greater than 6 tpy, you must demonstrate continuous compliance according to paragraphs (e)(1) and (2) of this section.

(1) You must reduce VOC emissions from each storage vessel are reduced by 95.0 percent or greater.

(2) If you use a control device to reduce VOC emissions, you must demonstrate continuous compliance with the performance requirements of § 60.5412(a)(2) using the procedure specified in paragraphs (e)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in § 60.5412(a)(2), you may demonstrate compliance according to paragraph (e)(2)(viii) of this section. You may switch between compliance with paragraphs (e)(2)(i) through (vii) of this section and compliance with paragraph (e)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next Annual Report, as required in § 60.5420(b), following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of § 60.5417(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with § 60.5417(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (e)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (e)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in § 60.5413(d), compliance with the operating parameter limit is achieved when the inlet gas flow rate is equal to or less than the value established under § 60.5413(d)(1)(ii).

(iv) You must operate the continuous monitoring system required in § 60.5417 at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of § 60.5412(a), you must demonstrate compliance by installing a device tested under the provisions in § 60.5413(d) and complying with the criteria in paragraphs (e)(2)(vii)(A) through (D) of this section.

(A) The inlet gas flow rate must meet the range specified by the manufacturer. You must measure the flow rate as specified in § 60.5417(d)(1)(viii)(A).

(B) A pilot flame must be present at all times of operation. You must monitor the pilot flame in accordance with § 60.5417(d)(1)(viii)(B).

(C) You must operate the combustion control device with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. You must perform a visible emissions test using Method 22 at 40 CFR part 60, appendix A–7 monthly. The observation period must be 2 hours and must follow Method 22.

(D) Compliance with the operating parameter limit is achieved when the criteria in paragraphs (e)(2)(vii)(D)(*1*) through (*5*) are met.

(*1*) The inlet gas flow rate monitored under paragraph (e)(2)(vii)(A) of this section is equal to or below the maximum established by the manufacturer.

(*2*) The pilot flame is present at all times; and

(*3*) During the visible emissions test performed under paragraph (e)(2)(vii)(C) of this section, the duration of visible emissions does not exceed a total of 5 minutes during the observation period. Devices failing the visible emissions test must follow the requirements in paragraphs (e)(2)(vii)(D)(*4*) and (*5*) of this section.

(*4*) Following the first failure, you must replace the fuel nozzle(s) and burner tubes.

(*5*) If, following replacement of the fuel nozzle(s) and burner tubes as specified in paragraph (e)(2)(vii)(D)(*4*) of this section, the visible emissions test is not passed in the next scheduled test, you must either conduct a performance test as specified in § 60.5413, or replace the device with another control device whose model was tested and meets the requirements in § 60.5413(d).

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in § 60.5412(a)(2), you must demonstrate compliance using the procedures in paragraphs (e)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to § 60.5417(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (e)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (e)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (e)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (e)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in § 60.5370, if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance dates. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in § 60.5370, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (e)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in § 60.5405(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(h) *Affirmative defense for violations of emission standards during malfunction.* In response to an action to enforce the standards set forth in §§ 60.5375, 60.5380, 60.5385, 60.5390, 60.5395, 60.5400, and 60.5405, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in § 60.5420(a), and must prove by a preponderance of evidence that:

(i) The violation:

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

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

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

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

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

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

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

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

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

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

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

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

(2) Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (h)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or

excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

§ 60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel and centrifugal compressor affected facility?

For each closed vent system or cover at your storage vessel or centrifugal compressor affected facility, you must comply with the requirements of paragraphs (a) through (g) of this section.

(a) *Inspections.* Except as provided in paragraphs (e) and (f) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.,* a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (e) and (f) of this section. You must maintain records of the inspection results as specified in § 60.5420(c)(7).

(4) For each bypass device, except as provided for in § 60.5411, you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to § 60.5420(c)(8).

(b) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover at your storage vessel or centrifugal compressor affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 at 40 CFR part 60, appendix A–7.

(2) The detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A–7, except that the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 at 40 CFR part 60, appendix A–7.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 at 40 CFR part 60, appendix A–7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A–7, except the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For

process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (d) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (e)(1) and (2) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(A) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(B) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in § 60.5420(c)(9).

§ 60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel or centrifugal compressor affected facility.

(a) You must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (j) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (j) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) You must design and operate the continuous monitoring system so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 60.5412. For each continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in

accordance with the site-specific monitoring plan.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 60.5413 that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.8 °C, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a performance test performed as specified in § 60.5413(b). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under § 60.5413(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better.

(B) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(2) A continuous monitoring system that measures the concentration level of organic compounds in the exhaust vent stream from the control device using an organic monitoring device equipped with a continuous recorder. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in § 60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 60.5412(a). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of § 60.5413(b) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of § 60.5413(c) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the minimum

operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under § 60.5413(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the maximum inlet gas flow rate based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of § 60.5413(b) to demonstrate that the condenser achieves the applicable performance requirements in § 60.5412(a), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of § 60.5413(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in § 60.5412(a), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (g)(6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section.

(2) If you meet § 60.5412(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 60.5415(e)(8)(iv) is less than 95.0 percent.

(3) If you meet § 60.5412(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in § 60.5415(e)(8)(iv)(A) or (B) is less than 90.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) and (ii) of this section are met.

(i) For each bypass line subject to § 60.5411(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to § 60.5411(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under § 60.5413(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under § 60.5413(d).

(ii) Failure of the monthly visible emissions test conducted under § 60.5415(e)(7)(iii) occurs.

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications required in § 60.7(a)(1) and (4), and according to paragraphs (a)(1) and (2) of this section, if you own or operate one or more of the affected facilities specified in § 60.5365 that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate a gas well, pneumatic controller or storage vessel affected facility you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a gas well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section to the Administrator and performance test reports as specified in paragraph (b)(7) of this section. The initial annual report is due 30 days after the end of the initial compliance period as determined according to § 60.5410. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (6) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each gas well affected facility, the information in paragraphs (b)(2)(i) through (ii) of this section.

(i) Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) and (ii) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with § 60.5380(a)(1), the records of closed vent system and cover inspections specified in paragraph (c)(6) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (ii) of this section.

(i) The cumulative number of hours or operation or the number of months since initial startup, October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (v) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in § 60.5390(c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) An identification of each storage vessel with VOC emissions greater than 6 tpy constructed, modified or reconstructed during the reporting period.

(ii) Documentation that the VOC emission rate is less than 6 tpy for meeting the requirements in § 60.5395(a).

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(7)(i) Within 60 days after the date of completing each performance test (see § 60.8 of this part) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(ii) All reports required by this subpart not subject to the requirements in paragraph (a)(2)(i) of this section must be sent to the Administrator at the appropriate address listed in § 63.13 of this part. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.,* by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (a)(2)(i) and (ii) of this section in paper format.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (10) of this section. All records must be maintained for at least 5 years.

(1) The records for each gas well affected facility as specified in paragraphs (c)(1)(i) through (v) of this section.

(i) Records identifying each well completion operation for each gas well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375.

(iii) Records required in § 60.5375(b) or (f) for each well completion operation conducted for each gas well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (B) of this section.

(A) For each gas well affected facility required to comply with the requirements of § 60.5375(a), you must record: The location of the well; the API well number; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.

(B) For each gas well affected facility required to comply with the requirements of § 60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(iv) For each gas well facility for which you claim an exception under § 60.5375(a)(3), you must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each gas well affected facility required to comply with both § 60.5375(a)(1) and (3), records of the digital photograph as specified in § 60.5410(a)(4).

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380.

(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or October 15, 2012, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement.

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (iv) of this section.

(i) If required to reduce emissions by complying with § 60.5395, the records specified in § 60.5416 of this subpart.

(ii) Records of the determination that the VOC emission rate is less than 6 tpy per storage vessel for the exemption under § 60.5395(a), including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§ 60.5395, 60.5411, 60.5412, and 60.5413.

(iv) For vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a vessel is removed from a site and, within 30 days, is either returned to or replaced by another vessel at the site to serve the same or similar function, then the entire period since the original vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(6) For each storage vessel or centrifugal compressor subject to the closed vent system inspection requirements of § 60.5416(a)(1) and (2), records of each inspection.

(7) For each storage vessel or centrifugal compressor subject to the cover requirements of § 60.5416(a)(3), a record of each inspection.

(8) For each storage vessel or centrifugal compressor subject to the bypass requirements of § 60.5416(a)(4), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(9) For each closed vent system used to comply with this subpart that must operate with no detectable emissions, a record of the monitoring conducted in accordance with § 60.5416(b)(13).

(10) Records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5413(c)(2) or (3)) and records of each carbon replacement as specified in § 60.5412(c)(1).

(11) For each storage vessel or centrifugal compressor subject to the control device requirements of § 60.5412, records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

§ 60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401(b)(1) of this subpart.

(1) When each leak is detected as specified in § 60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in § 60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482–4a(a). The designation of equipment subject to the provisions of § 60.482–4a(a) must be signed by the owner or operator.

§ 60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii).

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of § 60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c).

(c) An owner or operator must include the following information in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401(b)(3).

§ 60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in § 60.5405(a) and (b) and § 60.5407(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(d) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. For the purpose of these reports, excess emissions are defined as:

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407(b)(2). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less that 2 LT/D of H_2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with § 60.5407(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H_2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state.

§ 60.5425 What part of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

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

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

City gate means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (*e.g.,* level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Equipment means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas from the well to a processing facility, a mainline pipeline, re-injection, or other useful purpose.

Flowback means the process of allowing fluids to flow from a natural

gas well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The flowback period begins when material introduced into the well during the treatment returns to the surface immediately following hydraulic fracturing or refracturing. The flowback period ends with either well shut in or when the well is producing continuously to the flow line or to a storage vessel for collection, whichever occurs first.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas well or natural gas well means an onshore well drilled principally for production of natural gas.

Hydraulic fracturing or refracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401(g)(2) of this part.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Intermittent/snap-action pneumatic controller means a pneumatic controller that vents non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Low pressure gas well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the composition, moisture, or other limits set by the purchaser of the natural gas, regardless of whether such gas is sold.

Storage vessel means a unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of liquids or other materials. The following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 60.5420(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel since the original vessel was first located at the site.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A to part 60 of this chapter.

Total SO2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage vessel means a storage vessel stored below ground.

Well means an oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a gas well affected facility.

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

TABLE 1 TO SUBPART OOOO OF PART 60—REQUIRED MINIMUM INITIAL SO_2 EMISSION REDUCTION EFFICIENCY (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \leq X \leq 5.0$	$5.0 < X \leq 15.0$	$15.0 < X \leq 300.0$	$X > 300.0$
$Y \geq 50$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
$20 \leq Y < 50$	79.0	$88.5X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller.		97.9
$10 \leq Y < 20$	79.0	$88.5X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller.	93.5	93.5
$Y < 10$	79.0	79.0	79.0	79.0

TABLE 2 TO SUBPART OOOO OF PART 60—REQUIRED MINIMUM SO_2 EMISSION REDUCTION EFFICIENCY (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \leq X \leq 5.0$	$5.0 < X \leq 15.0$	$15.0 < X \leq 300.0$	$X > 300.0$
$Y \geq 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
$20 \leq Y < 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.9, whichever is smaller.		97.5
$10 \leq Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller.		90.8
$Y < 10$	74.0	74.0	74.0	74.0

E = The sulfur emission rate expressed as elemental sulfur, kilograms per hour (kg/hr) [pounds per hour (lb/hr)], rounded to one decimal place.
R = The sulfur emission reduction efficiency achieved in percent, carried to one decimal place.
S = The sulfur production rate, kilograms per hour (kg/hr) [pounds per hour (lb/hr)], rounded to one decimal place.

X = The sulfur feed rate from the sweetening unit (*i.e.,* the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

As stated in § 60.5425, you must comply with the following applicable General Provisions:

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5430.
§ 60.3	Units and abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in § 60.5420(a).
§ 60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels and centrifugal compressors.
§ 60.9	Availability of information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No	Requirements are specified in subpart OOOO.
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§ 60.14	Modification	Yes.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	Yes.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	Yes	Except that § 60.18 does not apply to flares.
§ 60.19	General notification and reporting requirement	Yes.	

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

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

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

■ 9. Section 63.14 is amended by:

■ a. Revising paragraphs (b) introductory text, (b)(28), and (b)(64);

■ b. Adding paragraphs (b)(73), (74), and (75); and

■ c. Revising paragraphs (i) introductory text and (i)(1) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, Telephone (610) 832–9585, and are also available at the following Web site: *http://www.astm.org*; or ProQuest, 789 East Eisenhower Parkway, Ann Arbor, MI 48106–1346, Telephone (734) 761–4700, and are also available at the following Web site: *http://www.proquest.com.*

* * * * *

(28) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (Approved October 1, 2004), IBR approved for §§ 60.485(g), 60.485a(g), 63.772(a), 63.772(e), 63.1282(a), 63.1282(d), 63.2351(b), 63.2354(b) and table 8 to subpart HHHHHHH of this part.

* * * * *

(64) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, approved October 1, 2005, IBR approved for table 4 to subpart ZZZZ of this part, table 5 to subpart DDDDD of this part, table 4 to subpart JJJJJJ of this part and §§ 63.772(e), 63.772(h), 63.1282(d) and 63.1282(g).

* * * * *

(73) ASTM D1945–03 (Reapproved 2010) Standard Test Method for Analysis of Natural Gas by Gas Chromatography (Approved January 1, 2010), IBR approved for §§ 63.772(h) and 63.1282(g).

(74) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (Approved May 10, 2003), IBR approved for §§ 63.772(h) and 63.1282(g).

(75) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (Approved June 1, 2006), IBR approved for §§ 63.772(h) and 63.1282(g).

* * * * *

(i) The following material is available for purchase from at least one of the following addresses: American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–

5990, Telephone (800) 843–2763, and are also available at the following Web site: *http://www.asme.org*; or HIS, Incorporated, 15 Inverness Way East, Englewood, CO 80112, Telephone (877) 413–5184, and are also available at the following Web site: *http://global.ihs.com*.

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], issued August 31, 1981 IBR approved for §§ 63.309(k), 63.772(e), 63.772(h), 63.865(b), 63.1282(d), 63.1282(g), 63.3166(a), 63.3360(e), 63.3545(a), 63.3555(a), 63.4166(a), 63.4362(a), 63.4766(a), 63.4965(a), 63.5160(d), 63.9307(c), 63.9323(a), 63.11148(e), 63.11155(e), 63.11162(f), 63.11163(g), 63.11410(j), 63.11551(a) and 63.11646(a), 63.11945, table 5 to subpart DDDDD of this part, table 4 to subpart JJJJJ of this part, table 5 to subpart UUUUU of this part and table 1 to subpart ZZZZZ of this part.

* * * * *

Subpart HH—[Amended]

■ 10. Section 63.760 is amended by:
■ a. Revising paragraph (a)(1) introductory text;
■ b. Revising paragraph (a)(1)(i);
■ c. Revising paragraph (a)(1)(iii);
■ d. Revising paragraph (a)(2);
■ e. Revising paragraph (b)(1)(i);
■ f. Adding paragraph (c);
■ g. Revising paragraph (f) introductory text;
■ h. Revising paragraph (f)(1);
■ i. Revising paragraph (f)(2);
■ j. Adding paragraphs (f)(7), (f)(8), and (f)(9); and
■ k. Removing and reserving paragraph (g)(1).

The revisions and additions read as follows:

§ 63.760 Applicability and designation of affected source.

(a) * * *

(1) Facilities that are major or area sources of hazardous air pollutants (HAP) as defined in § 63.761. Emissions for major source determination purposes can be estimated using the maximum natural gas or hydrocarbon liquid throughput, as appropriate, calculated in paragraphs (a)(1)(i) through (iii) of this section. As an alternative to calculating the maximum natural gas or hydrocarbon liquid throughput, the owner or operator of a new or existing source may use the facility's design maximum natural gas or hydrocarbon liquid throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction in accordance with § 63.10(b)(3). A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels, and becomes a major source, must comply thereafter with all provisions of this subpart applicable to a major source starting on the applicable compliance date specified in paragraph (f) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

(i) If the owner or operator documents, to the Administrator's satisfaction, a decline in annual natural gas or hydrocarbon liquid throughput, as appropriate, each year for the 5 years prior to October 15, 2012, the owner or operator shall calculate the maximum natural gas or hydrocarbon liquid throughput used to determine maximum potential emissions according to the requirements specified in paragraph (a)(1)(i)(A) of this section. In all other circumstances, the owner or operator shall calculate the maximum throughput used to determine whether a facility is a major source in accordance with the requirements specified in paragraph (a)(1)(i)(B) of this section.

(A) The maximum natural gas or hydrocarbon liquid throughput is the average of the annual natural gas or hydrocarbon liquid throughput for the 3 years prior to October 15, 2012, multiplied by a factor of 1.2.

(B) The maximum natural gas or hydrocarbon liquid throughput is the highest annual natural gas or hydrocarbon liquid throughput over the 5 years prior to October 15, 2012, multiplied by a factor of 1.2.

* * * * *

(iii) The owner or operator shall determine the maximum values for other parameters used to calculate emissions as the maximum for the period over which the maximum natural gas or hydrocarbon liquid throughput is determined in accordance with paragraph (a)(1)(i)(A) or (B) of this section. Parameters, other than glycol circulation rate, shall be based on either highest measured values or annual average. For estimating maximum potential emissions from glycol dehydration units, the glycol circulation rate used in the calculation shall be the unit's maximum rate under its physical and operational design consistent with the definition of potential to emit in § 63.2.

(2) Facilities that process, upgrade, or store hydrocarbon liquids.

* * * * *

(b) * * *

(1) * * *

(i) Each glycol dehydration unit as specified in paragraphs (b)(1)(i)(A) through (C) of this section.

(A) Each large glycol dehydration unit;

(B) Each small glycol dehydration unit for which construction commenced on or before August 23, 2011, is an existing small glycol dehydration unit; and

(C) Each small glycol dehydration unit for which construction commenced after August 23, 2011, is a new small glycol dehydration unit.

* * * * *

(c) Any source that determines it is not a major source but has actual emissions of 5 tons per year or more of a single HAP, or 12.5 tons per year or more of a combination of HAP (*i.e.,* 50 percent of the major source thresholds), shall update its major source determination within 1 year of the prior determination or October 15, 2012, whichever is later, and each year thereafter, using gas composition data measured during the preceding 12 months.

* * * * *

(f) The owner or operator of an affected major source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(1), (2), and (f)(7) through (9) of this section. The owner or operator of an affected area source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(3) through (6) of this section.

(1) Except as specified in paragraphs (f)(7) through (9) of this section, the owner or operator of an affected major source, the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with the applicable provisions of this subpart no later than June 17, 2002, except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) Except as specified in paragraphs (f)(7) through (9) of this section, the owner or operator of an affected major source, the construction or reconstruction of which commences on

or after February 6, 1998, shall achieve compliance with the applicable provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, other than production field facilities identified in (f)(9) of this section, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

* * * * *

(7) Each affected existing small glycol dehydration unit, as defined in § 63.761, located at a major source, that commenced construction before August 23, 2011, must achieve compliance no later than October 15, 2015, except as provided in § 63.6(i).

(8) Each affected new small glycol dehydration unit, as defined in § 63.761, located at a major source, that commenced construction on or after August 23, 2011, must achieve compliance immediately upon initial startup or October 15, 2012, whichever is later.

(9) A production field facility, as defined in § 63.761, constructed on or before August 23, 2011, that was previously determined to be an area source but becomes a major source (as defined in paragraph 3 of the major source definition in § 63.761) on the October 15, 2012 must achieve compliance no later than October 15, 2015, except as provided in § 63.6(i).

* * * * *

■ 11. Section 63.761 is amended by:

■ a. Adding, in alphabetical order, definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration unit,'' ''responsible official'' and ''small glycol dehydration unit'';

■ b. Revising the definitions for ''associated equipment,'' ''glycol dehydration unit baseline operations,'' and ''storage vessel''; and

■ c. Revising paragraph (3) of the definition for ''major source'' to read as follows:

§ 63.761 Definitions.

* * * * *

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

* * * * *

Associated equipment, as used in this subpart and as referred to in section 112(n)(4) of the Act, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the wellbore to the point of custody transfer, except glycol dehydration units and storage vessels.

* * * * *

BTEX means benzene, toluene, ethyl benzene and xylene.

* * * * *

Flare means a thermal oxidation system using an open flame (*i.e.,* without enclosure).

* * * * *

Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999 and the small glycol dehydrator unit operations as of August 23, 2011. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (*i.e.,* at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

* * * * *

Large glycol dehydration unit means a glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 85 thousand standard cubic meters per day and actual annual average benzene emissions equal to or greater than 0.90 Mg/yr, determined according to § 63.772(b). A glycol dehydration unit complying with the 0.9 Mg/yr control option under § 63.765(b)(1)(ii) is considered to be a large dehydrator.

Major source * * *

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

* * * * *

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected sources:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Act or the regulations promulgated thereunder are concerned; and

(ii) The designated representative for any other purposes under part 70.

* * * * *

Small glycol dehydration unit means a glycol dehydration unit, located at a major source, with an actual annual average natural gas flowrate less than 85 thousand standard cubic meters per day or actual annual average benzene emissions less than 0.90 Mg/yr, determined according to § 63.772(b).

* * * * *

Storage vessel means a tank or other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed primarily of non-earthen materials (*e.g.,* wood, concrete, steel, plastic) that provide structural support. The following process units are not considered storage vessels: Surge control vessels and knockout vessels.

* * * * *

■ 12. Section 63.762 is revised to read as follows:

§ 63.762 Affirmative defense for violations of emission standards during malfunction.

(a) The provisions set forth in this subpart shall apply at all times.

(b) [Reserved]

(c) [Reserved]

(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to

a claim for civil penalties for violations of such standards that are caused by malfunction, as defined in 40 CFR 63.2. Appropriate penalties may be assessed; however, if you fail to meet your burden of proving all of the requirements in the affirmative defense, the affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The violation:

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

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

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

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

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

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

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

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

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

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

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

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

(2) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 13. Section 63.764 is amended by:
■ a. Revising paragraph (e)(1) introductory text;
■ b. Revising paragraph (i); and
■ c. Adding paragraph (j).

The revisions and addition read as follows:

§ 63.764 General standards.

* * * * *

(e) *Exemptions.* (1) The owner or operator of an area source is exempt from the requirements of paragraph (d) of this section if the criteria listed in paragraph (e)(1)(i) or (ii) of this section are met, except that the records of the determination of these criteria must be maintained as required in § 63.774(d)(1).

* * * * *

(i) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, and a leak is detected, the owner or operator shall take further action as required by the applicable provisions of this subpart.

(j) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

■ 14. Section 63.765 is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraph (b)(1);
■ c. Revising paragraph (c)(2); and
■ d. Revising paragraph (c)(3).

The revisions read as follows:

§ 63.765 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in either paragraph (c)(1)(i) or paragraph (d)(1)(i) of § 63.764.

(b) * * *

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i), (ii), or (iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.761, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d).

(ii) The owner or operator of a large glycol dehydration unit shall connect the process vent to a control device or combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be reduced to a level less than 0.90 megagrams per year. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d), except that the performance levels specified in § 63.771(d)(1)(i) and (ii) do not apply.

(iii) You must limit BTEX emissions from each existing small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 1 of this section. You must limit BTEX emissions from each new small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 2 of this section. The limits determined using Equation 1 or Equation 2 must be met in accordance

with one of the alternatives specified in paragraphs (b)(1)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 3.28x10^{-4} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams}$$

Equation 1

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

3.28×10^{-4} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day.

$C_{i,BTEX}$ = average annual BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

$$EL_{BTEX} = 4.66x10^{-6} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

4.66×10^{-6} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day.

$C_{i,BTEX}$ = average annual BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

(A) Connect the process vent to a control device or combination of control devices through a closed-vent system. The closed vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(f).

(B) Meet the emissions limit through process modifications in accordance with the requirements specified in § 63.771(e).

(C) Meet the emissions limit for each small glycol dehydration unit using a combination of process modifications and one or more control devices through the requirements specified in paragraphs (b)(1)(iii)(A) and (B) of this section.

(D) Demonstrate that the emissions limit is met through actual uncontrolled operation of the small glycol dehydration unit. Document operational parameters in accordance with the requirements specified in § 63.771(e) and emissions in accordance with the requirements specified in § 63.772(b)(2).

* * * * *

(c) * * *

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications, or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.771(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i) through (iv) of this section, through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) For any large glycol dehydration unit, benzene emissions are reduced to a level less than 0.90 megagrams per year.

(iii) For each existing small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by Equation 1 of paragraph (b)(1)(iii) of this section.

(iv) For each new small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by Equation 2 of paragraph (b)(1)(iii) of this section.

■ 15. Section 63.766 is amended by:

■ a. Adding paragraph (b)(3); and

■ b. Revising paragraph (d) to read as follows:

§ 63.766 Storage vessel standards.

* * * * *

(b) * * *

(3) The owner or operator shall control air emissions by connecting the cover, through a closed-vent system that meets the conditions specified in § 63.771(c), to a process natural gas line.

* * * * *

(d) This section does not apply to storage vessels for which the owner or operator is subject to and controlled under the requirements specified in 40 CFR part 60, subparts Kb or OOOO; or is subject to and controlled under 40 CFR part 63 subparts G or CC. Storage vessels subject to and controlled under 40 CFR part 60, subpart OOOO shall submit the periodic reports specified in § 63.775(e).

■ 16. Section 63.769 is amended by:

■ a. Revising paragraph (b);

■ b. Revising paragraph (c) introductory text; and

■ c. Revising paragraph (c)(8).

The revisions read as follows:

§ 63.769 Equipment leak standards.

* * * * *

(b) This section does not apply to ancillary equipment and compressors for which the owner or operator is subject to and controlled under the requirements specified in subpart H of this part; or is subject to and controlled under the requirements specified in 40 CFR part 60, subpart OOOO. Ancillary equipment and compressors subject to and controlled under 40 CFR part 60, subpart OOOO shall submit the periodic reports specified in § 63.775(e).

(c) For each piece of ancillary equipment and each compressor subject to this section located at an existing or new source, the owner or operator shall meet the requirements specified in 40 CFR part 61, subpart V, §§ 61.241 through 61.247, except as specified in paragraphs (c)(1) through (8) of this section, except that for valves subject to § 61.242–7(b) or § 61.243–1, a leak is detected if an instrument reading of 500 ppm or greater is measured. A leak detected from a valve at a source constructed on or before August 23, 2011 shall be repaired in accordance with the schedule in § 61.242–7(d), or by October 15, 2013, whichever is later. A leak detected from a valve at a source constructed after August 23, 2011 shall be repaired in accordance with the schedule in § 61.242–7(d), or by October 15, 2012, whichever is later.

* * * * *

(8) Flares, as defined in § 63.761, used to comply with this subpart shall comply with the requirements of § 63.11(b).

■ 17. Section 63.771 is amended by:
■ a. Revising paragraph (c)(1);
■ b. Revising the heading of paragraph (d);
■ c. Adding paragraph (d) introductory text;
■ d. Revising paragraph (d)(1)(i)(C);
■ e. Revising paragraph (d)(1)(ii);
■ f. Revising paragraph (d)(1)(iii);
■ g. Revising paragraph (d)(4)(i);
■ h. Revising paragraph (d)(5)(i);
■ i. Revising paragraph (e)(2);
■ j. Revising paragraph (e)(3) introductory text;
■ k. Revising paragraph (e)(3)(ii); and
■ l. Adding paragraph (f).

The revisions and additions read as follows:

§ 63.771 Control equipment requirements.

* * * * *

(c) *Closed-vent system requirements.* (1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

* * * * *

(d) *Control device requirements for sources except small glycol dehydration units.* Owners and operators of small glycol dehydration units, shall comply with the control device requirements in paragraph (f) of this section.

(1) * * *

(i) * * *

(C) Operates at a minimum temperature of 760 degrees C, provided the control device has demonstrated, under § 63.772(e), that combustion zone temperature is an indicator of destruction efficiency.

* * * * *

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.772(e).

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

* * * * *

(4) * * *

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the HAP emissions unit or units through the closed-vent system to the control device, as required under § 63.765, § 63.766, and § 63.769. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

* * * * *

(5) * * *

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.774(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.775(d)(5)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.772(e)(2)(xii).

* * * * *

(e) * * *

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.765(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.765(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (ii) of this section.

* * * * *

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) *Control device requirements for small glycol dehydration units.* (1) The control device used to meet BTEX the emission limit calculated in § 63.765(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to meet the levels specified in paragraphs (f)(1)(i)(A) or (B) of this section. If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(A) The mass content of BTEX in the gases vented to the device is reduced as determined in accordance with the requirements of § 63.772(e).

(B) The concentration of either TOC or total HAP in the exhaust gases at the outlet of the device is reduced to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 63.772(e).

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.772(e).

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.773(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.772(f) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1)(ii) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

■ 18. Section 63.772 is amended by:
■ a. Revising paragraph (b) introductory text;
■ b. Revising paragraph (b)(1)(ii);
■ c. Revising paragraph (b)(2);
■ d. Revising paragraph (c)(6)(i);
■ e. Adding paragraph (d);
■ f. Revising paragraph (e) introductory text;
■ g. Revising paragraphs (e)(1)(i) through (v);
■ h. Revising paragraph (e)(2);
■ i. Revising paragraph (e)(3) introductory text;
■ j. Revising paragraph (e)(3)(i)(B);
■ k. Revising paragraph (e)(3)(iv)(C)(*1*);
■ l. Adding paragraphs (e)(3)(v) and (vi);
■ m. Revising paragraph (e)(4) introductory text;
■ n. Revising paragraph (e)(4)(i);
■ o. Revising paragraph (e)(5);
■ p. Revising paragraph (f) introductory text;
■ q. Revising paragraphs (f)(2) and (3);
■ r. Adding paragraphs (f)(4) through (6);
■ s. Revising paragraph (g) introductory text;
■ t. Revising paragraph (g)(1) and paragraph (g)(2) introductory text;
■ u. Revising paragraph (g)(2)(iii);
■ v. Revising paragraph (g)(3);
■ w. Adding paragraph (h); and
■ x. Adding paragraph (i).

The revisions and additions read as follows:

§ 63.772 Test methods, compliance procedures, and compliance demonstrations.

* * * * *

(b) *Determination of glycol dehydration unit flowrate, benzene emissions, or BTEX emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

(1) * * *

(ii) The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

(2) The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (b)(2)(i) or (ii) of this section. Emissions shall be determined either uncontrolled, or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement using the methods in § 63.772(a)(1)(i) or (ii), or an alternative method according to § 63.7(f). Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

(c) * * *

(6) * * *

(i) Except as provided in paragraph (c)(6)(ii) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inert gases that are not organic hazardous air pollutants or volatile organic compounds, the average stream response factor shall be calculated on an inert-free basis.

* * * * *

(d) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph applies to the test procedures for small dehydration units.

(1) If the owner or operator is using a control device to comply with the emission limit in § 63.765(b)(1)(iii), the requirements of paragraph (e) of this section apply. Compliance is demonstrated using the methods specified in paragraph (f) of this section.

(2) If no control device is used to comply with the emission limit in § 63.765(b)(1)(iii), the owner or operator must determine the glycol dehydration unit BTEX emissions as specified in paragraphs (d)(2)(i) through (iii) of this section. Compliance is demonstrated if the BTEX emissions determined as specified in paragraphs (d)(2)(i) through (iii) are less than the emission limit calculated using the equation in § 63.765(b)(1)(iii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the outlet of the glycol dehydration unit process vent. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) The BTEX emissions from the outlet of the glycol dehydration unit process vent shall be determined using the procedures specified in paragraph (e)(3)(v) of this section. As an alternative, the mass rate of BTEX at the outlet of the glycol dehydration unit process vent may be calculated using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and shall be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1). When the BTEX mass rate is calculated for glycol dehydration units using the model GRI–GLYCalc™, all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed.

(e) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1) using a performance test as specified in paragraph (e)(3) of this section. Owners or operators using a condenser have the option to use a design analysis as specified in paragraph (e)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (e)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent. Flares shall meet the provisions in paragraph (e)(2) of this section. As an alternative to conducting a performance test under this section for combustion control devices, a control device that can be

demonstrated to meet the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1) through a performance test conducted by the manufacturer, as specified in paragraph (h) of this section, can be used.

(1) * * *

(i) Except as specified in paragraph (e)(2) of this section, a flare, as defined in § 63.761, that is designed and operated in accordance with § 63.11(b);

(ii) Except for control devices used for small glycol dehydration units, a boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) Except for control devices used for small glycol dehydration units, a boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) Except for control devices used for small glycol dehydration units, a boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H; or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) Except for control devices used for small glycol dehydration units, a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O; or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

* * * * *

(2) An owner or operator shall design and operate each flare, as defined in § 63.761, in accordance with the requirements specified in § 63.11(b) and the compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1), the owner or operator shall use the test methods and procedures specified in paragraphs (e)(3)(i) through (v) of this section. The initial and periodic performance tests shall be conducted according to the schedule specified in paragraph (e)(3)(vi) of this section.

(i) * * *

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.771(d)(1)(i)(B), or the BTEX emission limit specified in § 63.765(b)(1)(iii) the sampling site shall be located at the outlet of the combustion device.

* * * * *

(iv) * * *

(C) * * *

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B, 40 CFR part 60, appendix A, ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 63.14) shall be used to determine the oxygen concentration. The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

* * * * *

(v) To determine compliance with the BTEX emission limit specified in § 63.765(b)(1)(iii) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (Reapproved 2004), as specified in § 63.772(a)(1)(ii) (incorporated by reference as specified in § 63.14); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of BTEX (E_o) shall be computed using the equations and procedures specified in paragraphs (e)(3)(v)(B)(*1*) and (*2*) of this section.

(*1*) The following equation shall be used:

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj}M_{oj}\right)Q_o$$

Where:

E_o = Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour.

C_{oj} = Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume.

M_{oj} = Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole.

Q_o = Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C.

n = Number of components in sample.

(*2*) When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (e)(3)(v)(B)(*1*) of this section.

(vi) The owner or operator shall conduct performance tests according to the schedule specified in paragraphs (e)(3)(vi)(A) and (B) of this section.

(A) An initial performance test shall be conducted within 180 days after the compliance date that is specified for each affected source in § 63.760(f)(7) through (8), except that the initial performance test for existing combustion control devices (*i.e.,* control devices installed on or before August 23, 2011) at major sources shall be conducted no later than October 15, 2015. If the owner or operator of an existing combustion control device at a major source chooses to replace such device with a control device whose model is tested under § 63.772(h), then the newly installed device shall comply with all provisions of this subpart no later than October 15, 2015. The performance test results shall be submitted in the Notification of Compliance Status Report as required in § 63.775(d)(1)(ii).

(B) Periodic performance tests shall be conducted for all control devices required to conduct initial performance tests except as specified in paragraphs (e)(3)(vi)(B)(*1*) and (*2*) of this section. The first periodic performance test shall be conducted no later than 60 months after the initial performance test required in paragraph (e)(3)(vi)(A) of this section. Subsequent periodic performance tests shall be conducted at intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit. The periodic performance test results must be submitted in the next Periodic Report as specified in § 63.775(e)(2)(xi). Combustion control devices meeting the criteria in either paragraph (e)(3)(vi)(B)(*1*) or (*2*) of this section are not required to conduct periodic performance tests.

(*1*) A control device whose model is tested under, and meets the criteria of, § 63.772(h), or

(*2*) A combustion control device demonstrating during the performance test under § 63.772(e) that combustion

zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 degrees C.

(4) For a condenser design analysis conducted to meet the requirements of § 63.771(d)(1), (e)(3)(ii), or (f)(1), the owner or operator shall meet the requirements specified in paragraphs (e)(4)(i) and (ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.775(d)(1)(i).

(i) The condenser design analysis shall include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the condenser design analysis, an owner or operator may elect to use the procedures specified in paragraph (e)(5) of this section.

* * * * *

(5) As an alternative to the procedures in paragraph (e)(4)(i) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(f) *Compliance demonstration for control device performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.771(d)(1)(i), (e)(3), and (f)(1). Compliance shall be demonstrated using the requirements in paragraphs (f)(1) through (3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.771(d)(1)(ii), (e)(3), or (f)(1) may demonstrate compliance according to paragraph (g) of this section. An owner or operator may switch between compliance with paragraph (f) of this section and compliance with paragraph (g) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.775(e), following the change.

* * * * *

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.773(d)(4) except that the inlet gas flowrate to the control device shall not be averaged.

(3) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (f)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (f)(1) of this section. For inlet gas flowrate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.772(h) or under the performance test conducted under § 63.772(e), as applicable.

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS required in § 63.773(d) must be operated at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(5) Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

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

(g) *Compliance demonstration with percent reduction or emission limit performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.771(d)(1)(ii), (e)(3), or (f)(1) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (g)(1) through (3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to § 63.773(d)(5)(ii). For sources required to meet the BTEX limit in accordance with § 63.771(e) or (f)(1) the owner or operator shall identify the minimum percent reduction necessary to meet the BTEX limit.

(2) Compliance with the requirements in § 63.771(d)(1)(ii), (e)(3), or (f)(1) shall be demonstrated by the procedures in paragraphs (g)(2)(i) through (iii) of this section.

* * * * *

(iii) Except as provided in paragraphs (g)(2)(iii)(A) and (B) of this section, at the end of each operating day, the owner or operator shall calculate the 365-day average HAP, or BTEX, emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (g)(2)(ii) of this section for the preceding 365 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.771(e), the 365-day average HAP, or BTEX, emission reduction shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency as determined in paragraph (g)(2)(ii) of this section, both for the previous 365 operating days.

(A) After the compliance dates specified in § 63.760(f), an owner or operator with less than 120 days of data for determining average HAP, or BTEX, emission reduction, as appropriate, shall calculate the average HAP, or BTEX emission reduction, as appropriate, for the first 120 days of operation after the compliance dates. For sources required to meet the overall 95.0 percent reduction requirement, compliance is achieved if the 120-day average HAP emission reduction is equal to or greater than 90.0 percent. For sources required to meet the BTEX limit under § 63.765(b)(1)(iii), compliance is achieved if the average BTEX emission reduction is at least 95.0 percent of the required 365-day value identified under paragraph (g)(1) of this section (*i.e.,* at least 76.0 percent if the 365-day design value is 80.0 percent).

(B) After 120 days and no more than 364 days of operation after the compliance dates specified in

§ 63.760(f), the owner or operator shall calculate the average HAP emission reduction as the HAP emission reduction averaged over the number of days between the current day and the applicable compliance date. For sources required to meet the overall 95.0-percent reduction requirement, compliance with the performance requirements is achieved if the average HAP emission reduction is equal to or greater than 90.0 percent. For sources required to meet the BTEX limit under § 63.765(b)(1)(iii), compliance is achieved if the average BTEX emission reduction is at least 95.0 percent of the required 365-day value identified under paragraph (g)(1) of this section (*i.e.,* at least 76.0 percent if the 365-day design value is 80.0 percent).

(3) If the owner or operator has data for 365 days or more of operation, compliance is achieved based on the applicable criteria in paragraphs (g)(3)(i) or (ii) of this section.

(i) For sources meeting the HAP emission reduction specified in § 63.771(d)(1)(ii) or (e)(3) the average HAP emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than 95.0 percent.

(ii) For sources required to meet the BTEX limit under § 63.771(e)(3) or (f)(1), compliance is achieved if the average BTEX emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than the minimum percent reduction identified in paragraph (g)(1) of this section.

(h) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer shall demonstrate that a specific model of control device achieves the performance requirements in paragraph (h)(7) of this section by conducting a performance test as specified in paragraphs (h)(2) through (6) of this section.

(2) Performance testing shall consist of three one-hour (or longer) test runs for each of the four following firing rate settings making a total of 12 test runs per test. Propene (propylene) gas shall be used for the testing fuel. All fuel analyses shall be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures shall be tested simultaneously and with all burners operational. Results shall be reported for the each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data shall be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. Data shall be submitted with the test report in accordance with paragraph (h)(8)(iii) of this section.

(4) Inlet gas testing shall be conducted as specified in paragraphs (h)(4)(i) through (iii) of this section.

(i) The inlet gas flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure inlet gas flowrate at the control device inlet location. The fitting for filling inlet gas sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet gas flowrate shall be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the inlet gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet gas fuel sampling shall be conducted in accordance with the criteria in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3 hour period. Filling shall be conducted as specified in the following:

(*1*) Open the canister sampling valve at the beginning of the total hydrocarbon (THC) test, and close the canister at the end of each THC run.

(*2*) Fill one canister across the three test runs for each THC test such that one composite fuel sample exists for each test condition.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each inlet gas sample shall be analyzed using the following methods. The results shall be included in the test report.

(*1*) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*3*) Higher heating value using ASTM D3588–98 (Reapproved 2003) or ASTM D4891–89 (Reapproved 2006) (incorporated by reference as specified in § 63.14).

(5) Outlet testing shall be conducted in accordance with the criteria in paragraphs (h)(5)(i) through (v) of this section.

(i) Sampling and flowrate measured in accordance with the following:

(A) The outlet sampling location shall be a minimum of 4 equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports shall be used.

(B) Flowrate shall be measured using Method 1, 40 CFR part 60, Appendix 1, for determining flow measurement traverse point location; and Method 2, 40 CFR part 60, Appendix 1, shall be used to measure duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer or other pressure measurement device shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (h)(4)(iii)(B) and (h)(5)(ii)(A) and (B) of this section.

(A) An integrated bag sample shall be collected during the Method 4, 40 CFR

part 60, Appendix A, moisture test. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the following criteria:

(*1*) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(*2*) The sampling line shall be purged with stack gas before opening the valve and beginning to fill the bag.

(*3*) The bag contents shall be vigorously mixed prior to the GC analysis.

(*4*) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, Appendix A, shall be modified by using EPAAlt–045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, the initial calibration using at least three concentration levels shall be repeated.

(B) Report the molecular weight of: O_2, CO_2, methane (CH4), and N_2 and include in the test report submitted under § 63.775(d)(iii). Moisture shall be determined using Method 4, 40 CFR part 60, Appendix A. Traverse both ports with the Method 4, 40 CFR part 60, Appendix A, sampling train during each test run. Ambient air shall not be introduced into the Method 3C, 40 CFR part 60, Appendix A, integrated bag sample during the port change.

(iii) Carbon monoxide shall be determined using Method 10, 40 CFR part 60, Appendix A, or ASTM D6522–00 (Reapproved 2005), (incorporated by reference as specified in § 63.14). The test shall be run at the same time and with the sample points used for the EPA Method 25A, 40 CFR part 60, Appendix A, testing. An instrument range of 0–10 per million by volume-dry (ppmvd) shall be used.

(iv) Visible emissions shall be determined using Method 22, 40 CFR part 60, Appendix A. The test shall be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(v) Excess air shall be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, Appendix A, equation 3B–1 or ANSI/ASME PTC 19.10, 1981-Part 10 (manual portion only) (incorporated by reference as specified in § 63.14).

(6) Total hydrocarbons (THC) shall be determined as specified by the following criteria:

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, Appendix A, except the option for locating the probe in the center 10 percent of the stack shall not be allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test.

(ii) A valid test shall consist of three Method 25A, 40 CFR part 60, Appendix A, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements shall be reported in terms of ppmvw as propane.

(vi) THC results shall be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, Appendix A.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(7) Performance test criteria:

(i) The control device model tested must meet the criteria in paragraphs (h)(7)(i)(A) through (C) of this section:

(A) Method 22, 40 CFR part 60, Appendix A, results under paragraph (h)(5)(v) of this section with no indication of visible emissions, and

(B) Average Method 25A, 40 CFR part 60, Appendix A, results under paragraph (h)(6) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2, and

(C) Average CO emissions determined under paragraph (h)(5)(iv) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess combustion air shall be equal to or greater than 150 percent.

(ii) The manufacturer shall determine a maximum inlet gas flowrate which shall not be exceeded for each control device model to achieve the criteria in paragraph (h)(7)(i) of this section.

(iii) A control device meeting the criteria in paragraphs (h)(7)(i)(A) through (C) of this section will have demonstrated a destruction efficiency of 95.0 percent for HAP regulated under this subpart.

(8) The owner or operator of a combustion control device model tested under this section shall submit the information listed in paragraphs (h)(8)(i) through (iii) of this section in the test report required under § 63.775(d)(1)(iii).

(i) Full schematic of the control device and dimensions of the device components.

(ii) Design net heating value (minimum and maximum) of the device.

(iii) Test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flowrate.

(iv) Air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (h)(8)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flowrate.

(O) Wind velocity and direction.

(vi) The test report shall include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values.

(i) *Compliance demonstration for combustion control devices—manufacturers' performance test.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (h) of this section. Owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1), by installing a device tested under paragraph (h) of this section and complying with the following criteria:

(1) The inlet gas flowrate shall meet the range specified by the manufacturer. Flowrate shall be calculated as specified in § 63.773(d)(3)(i)(H)(*1*).

(2) A pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with § 63.773(d)(3)(i)(H)(*2*).

(3) Devices shall be operated with no visible emissions, except for periods not

to exceed a total of 2 minutes during any hour. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed each calendar quarter. The observation period shall be 1 hour and shall be conducted according to EPA Method 22, 40 CFR part 60, Appendix A.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flowrate monitored under paragraph (i)(1) of this section is equal to or below the maximum established by the manufacturer; and

(ii) The pilot flame is present at all times; and

(iii) During the visible emissions test performed under paragraph (i)(3) of this section the duration of visible emissions does not exceed a total of 2 minutes during the observation period. Devices failing the visible emissions test shall follow manufacturers repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit shall be recorded in a maintenance and repair log and shall be available on site for inspection.

(iv) Following return to operation from maintenance or repair activity, each device must pass a Method 22 visual observation as described in paragraph (i)(3) of this section.

■ 19. Section 63.773 is amended by:
■ a. Adding paragraph (b);
■ b. Revising paragraph (d)(1) introductory text;
■ c. Revising paragraph (d)(1)(ii) and adding paragraphs (d)(1)(iii) and (iv);
■ d. Revising paragraph (d)(2);
■ e. Revising paragraph (d)(3)(i)(A);
■ f. Revising paragraph (d)(3)(i)(D);
■ g. Revising paragraph (d)(3)(i)(G);
■ h. Adding paragraph (d)(3)(i)(H);
■ i. Revising paragraph (d)(4);
■ j. Revising paragraph (d)(5)(i);
■ k. Revising paragraphs (d)(5)(ii)(A) through (C);
■ l. Revising paragraph (d)(6) introductory text;
■ m. Revising paragraphs (d)(6)(ii) and (iii);
■ n. Adding paragraph (d)(6)(vi);
■ o. Revising paragraph (d)(7); and
■ p. Removing paragraphs (d)(8) and (9).

The revisions and additions read as follows:

§ 63.773 Inspection and monitoring requirements.

* * * * *

(b) The owner or operator of a control device whose model was tested under § 63.772(h) shall develop an inspection and maintenance plan for each control device. At a minimum, the plan shall contain the control device manufacturer's recommendations for ensuring proper operation of the device. Semi-annual inspections shall be conducted for each control device with maintenance and replacement of control device components made in accordance with the plan.

* * * * *

(d) *Control device monitoring requirements.* (1) For each control device, except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (7) of this section. Owners or operators that install and operate a flare in accordance with § 63.771(d)(1)(iii) or (f)(1)(iii) are exempt from the requirements of paragraphs (d)(4) and (5) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.771(d), (e)(3), or (f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

* * * * *

(ii) A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph (d) of this section and in § 63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in your approved site-specific monitoring plan. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (d)(1)(ii)(A) through (E) of this section in your site-specific monitoring plan.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(B) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements;

(C) Equipment performance checks, system accuracy audits, or other audit procedures;

(D) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (3); and

(E) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(iii) The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(iv) The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

(2) An owner or operator is exempt from the monitoring requirements specified in paragraphs (d)(3) through (7) of this section for the following types of control devices:

(i) Except for control devices for small glycol dehydration units, a boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel; or

(ii) Except for control devices for small glycol dehydration units, a boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) * * *

(i) * * *

(A) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 63.772(e) that the combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(D) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.772(e)(3) and shall be based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device model whose model is tested under § 63.772(h):

(*1*) The owner or operator shall determine actual average inlet waste gas flowrate using the model GRI–GLYCalc ™, Version 3.0 or higher, ProMax, or AspenTech HYSYS. Inputs to the models shall be representative of actual operating conditions of the controlled unit. The determination shall be performed to coincide with the visible emissions test under § 63.772(i)(3);

(*2*) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

* * * * *

(4) Using the data recorded by the monitoring system, except for inlet gas flowrate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) * * *

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.771(d)(1), (e)(3)(ii), or (f)(1). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.772(e)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(B) If the owner or operator uses a condenser design analysis in accordance with the requirements of § 63.772(e)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the condenser design analysis and may be supplemented by the condenser manufacturer's recommendations.

(C) If the owner or operator operates a control device where the performance test requirement was met under § 63.772(h) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii), or (f)(1), then the maximum inlet gas flowrate shall be established based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(ii) * * *

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.772(e)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.771(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination of both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.772(e)(4)(i) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraph (d)(5)(ii)(B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI–95/0368.1) as inputs for the model GRI–GLYCalc ™, Version 3.0 or higher, to generate a condenser performance curve.

(6) An excursion for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (d)(6)(i) through (vi) of this section being met. When multiple operating parameters are monitored for the same control device and during the same operating day and more than one of these operating parameters meets an excursion criterion specified in paragraphs (d)(6)(i) through (vi) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

* * * * *

(ii) For sources meeting § 63.771(d)(1)(ii), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent. For sources meeting § 63.771(f)(1), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent of the identified 365-day required percent reduction.

(iii) For sources meeting § 63.771(d)(1)(ii), if an owner or operator has less than 365 days of data, an excursion occurs when the average condenser efficiency calculated according to the procedures specified in § 63.772(g)(2)(iii)(A) or (B) is less than 90.0 percent. For sources meeting § 63.771(f)(1), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than the identified 365-day required percent reduction.

* * * * *

(vi) For control device whose model is tested under § 63.772(h) an excursion occurs when:

(A) The inlet gas flowrate exceeds the maximum established during the test conducted under § 63.772(h).

(B) Failure of the quarterly visible emissions test conducted under § 63.772(i)(3) occurs.

(7) For each excursion, the owner or operator shall be deemed to have failed to have applied control in a manner that achieves the required operating parameter limits. Failure to achieve the required operating parameter limits is a violation of this standard.

* * * * *

■ 20. Section 63.774 is amended by:
■ a. Revising paragraph (b)(3) introductory text;
■ b. Removing and reserving paragraph (b)(3)(ii);
■ c. Revising paragraph (b)(4)(ii) introductory text;
■ d. Adding paragraph (b)(4)(ii)(C);
■ e. Revising paragraph (b)(4)(iii);
■ f. Adding paragraph (b)(7)(ix); and
■ g. Adding paragraphs (g) through (i).

The revisions and additions read as follows:

§ 63.774 Recordkeeping requirements.

* * * * *

(b) * * *

(3) Records specified in § 63.10(c) for each monitoring system operated by the

owner or operator in accordance with the requirements of § 63.773(d). Notwithstanding the requirements of § 63.10(c), monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

* * * * *

(4) * * *

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.773(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section.

* * * * *

(C) For a control device whose model is tested under § 63.772(h), the records required in paragraph (h) of this section.

(iii) Hourly records of the times and durations of all periods when the vent stream is diverted from the control device or the device is not operating.

* * * * *

(7) * * *

(ix) Records identifying the carbon replacement schedule under § 63.771(d)(5) and records of each carbon replacement.

* * * * *

(g) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.764(j), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(h) Record the following when using a control device whose model is tested under § 63.772(h) to comply with § 63.771(d), (e)(3)(ii), and (f)(1):

(1) All visible emission readings and flowrate calculations made during the compliance determination required by § 63.772(i); and

(2) All hourly records and other recorded periods when the pilot flame is absent.

(i) The date the semi-annual maintenance inspection required under § 63.773(b) is performed. Include a list of any modifications or repairs made to the control device during the inspection and other maintenance performed such as cleaning of the fuel nozzles.

■ 21. Section 63.775 is amended by:
■ a. Revising paragraph (b)(1);
■ b. Revising paragraph (b)(6);
■ c. Removing and reserving paragraph (b)(7);
■ d. Revising paragraph (c)(1);
■ e. Revising paragraph (c)(6);
■ f. Revising paragraph (c)(7)(i);
■ g. Revising paragraph (d)(1)(i);
■ h. Revising paragraph (d)(1)(ii) introductory text;
■ i. Revising paragraph (d)(5)(ii);
■ j. Adding paragraph (d)(5)(iv);
■ k. Revising paragraph (d)(11);
■ l. Adding paragraphs (d)(13) and (d)(14);
■ m. Revising paragraphs (e)(2) introductory text, (e)(2)(ii)(B) and (C);
■ n. Adding paragraphs (e)(2)(ii)(E) and (F);
■ o. Adding paragraphs (e)(2)(xi) through (xiv); and
■ p. Adding paragraph (g).

The revisions and additions read as follows:

§ 63.775 Reporting requirements.

* * * * *

(b) * * *

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted as provided in paragraphs (b)(1)(i) and (ii) of this section.

(i) Except as otherwise provided in paragraph (b)(1)(ii) of this section, the initial notifications shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000, and plan to be area sources by June 17, 2002, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(ii) An affected source identified under § 63.760(f)(7) or (9) shall submit an initial notification required for existing affected sources under § 63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by October 15, 2013, whichever is later. An affected source identified under § 63.760(f)(7) or (9) that plans to be an area source by October 15, 2015, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.764(j), including actions taken to correct a malfunction.

* * * * *

(c) * * *

(1) The initial notifications required under § 63.9(b)(2) not later than January 3, 2008. In addition to submitting your initial notification to the addressees specified under § 63.9(a), you must also submit a copy of the initial notification to the EPA's Office of Air Quality Planning and Standards. Send your notification via email to *Oil and Gas Sector@epa.gov* or via U.S. mail or other mail delivery service to U.S. EPA, Sector Policies and Programs Division/ Fuels and Incineration Group (E143–01), Attn: Oil and Gas Project Leader, Research Triangle Park, NC 27711.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.764(j), including actions taken to correct a malfunction.

(7) * * *

(i) Documentation of the source's location relative to the nearest UA plus offset and UC boundaries. This information shall include the latitude and longitude of the affected source; whether the source is located in an urban cluster with 10,000 people or more; the distance in miles to the nearest urbanized area boundary if the source is not located in an urban cluster with 10,000 people or more; and the name of the nearest urban cluster with 10,000 people or more and nearest urbanized area.

* * * * *

(d) * * *

(1) * * *

(i) The condenser design analysis documentation specified in

§ 63.772(e)(4) of this subpart, if the owner or operator elects to prepare a design analysis.

(ii) If the owner or operator is required to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.772(e)(3) and that the test conditions are representative of current operating conditions. If the owner or operator operates a combustion control device model tested under § 63.772(h), an electronic copy of the performance test results shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

* * * * *

(5) * * *

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.773(d)(5). This explanation shall include any data and calculations used to develop the value and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1).

* * * * *

(iv) For each carbon adsorber, the predetermined carbon replacement schedule as required in § 63.771(d)(5)(i).

* * * * *

(11) The owner or operator shall submit the analysis prepared under § 63.771(e)(2) to demonstrate the conditions by which the facility will be operated to achieve the HAP emission reduction of 95.0 percent, or the BTEX limit in § 63.765(b)(1)(iii), through process modifications or a combination of process modifications and one or more control devices.

* * * * *

(13) If the owner or operator installs a combustion control device model tested under the procedures in § 63.772(h), the data listed under § 63.772(h)(8).

(14) For each combustion control device model tested under § 63.772(h), the information listed in paragraphs (d)(14)(i) through (vi) of this section.

(i) Name, address and telephone number of the control device manufacturer.

(ii) Control device model number.

(iii) Control device serial number.

(iv) Date the model of control device was tested by the manufacturer.

(v) Manufacturer's HAP destruction efficiency rating.

(vi) Control device operating parameters, maximum allowable inlet gas flowrate.

(e) * * *

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (ix) of this section, as applicable.

* * * * *

(ii) * * *

(B) For each excursion caused when the 365-day average condenser control efficiency is less than the value specified in § 63.773(d)(6)(ii), the report must include the 365-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

(C) For each excursion caused when condenser control efficiency is less than the value specified in § 63.773(d)(6)(iii), the report must include the average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

* * * * *

(E) For each excursion caused when the maximum inlet gas flowrate identified under § 63.772(h) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

(F) For each excursion caused when visible emissions determined under § 63.772(i) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred, repairs affected to the unit, and date the unit was returned to service.

* * * * *

(xi) The results of any periodic test as required in § 63.772(e)(3) conducted during the reporting period.

(xii) For each carbon adsorber used to meet the control device requirements of § 63.771(d)(1), records of each carbon replacement that occurred during the reporting period.

(xiii) For combustion control device inspections conducted in accordance with § 63.773(b) the records specified in § 63.774(i).

(xiv) Certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

* * * * *

(g) *Electronic reporting.* (1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(2) All reports required by this subpart not subject to the requirements in paragraph (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.*, by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (g)(1) of this section in paper format.

■ 22. Appendix to subpart HH of part 63 is amended by revising Table 2 to read as follows:

Appendix to Subpart HH of Part 63—Tables

* * * * *

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH

General provisions reference	Applicable to subpart HH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6)	Yes.	
§ 63.1(a)(7) through (a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12)	Yes.	
§ 63.1(b)(1)	No	Subpart HH specifies applicability.
§ 63.1(b)(2)	No	Section reserved.
§ 63.1(b)(3)	Yes.	
§ 63.1(c)(1)	No	Subpart HH specifies applicability.
§ 63.1(c)(2)	Yes	Subpart HH exempts area sources from the requirement to obtain a Title V permit unless otherwise required by law as specified in § 63.760(h).
§ 63.1(c)(3) and (c)(4)	No	Section reserved.
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1) through (a)(2)	Yes.	
§ 63.4(a)(3) through (a)(5)	No	Section reserved.
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	Yes.	
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	No	Section Reserved.
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) through (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)(1)(i)	No	See § 63.764(j) for general duty requirement.
§ 63.6(e)(1)(ii)	No.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	No	Section reserved.
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	
§ 63.6(h)(1)	No.	
§ 63.6(h)(2) through (h)(9)	Yes.	
§ 63.6(i)(1) through (i)(14)	Yes.	
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(a)(4)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	No.	
§ 63.8(c)(1)(i)	No.	
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	No.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	Yes.	
§ 63.8(c)(4)(i)	No	Subpart HH does not require continuous opacity monitors.
§ 63.8(c)(4)(ii)	Yes.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)(1)	Yes.	
§ 63.8(d)(2)	Yes.	
§ 63.8(d)(3)	Yes	Except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.8(e)	Yes	Subpart HH does not specifically require continuous emissions monitor performance evaluation, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	Yes.	
§ 63.8(g)	No	Subpart HH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification. Major and area sources that meet § 63.764(e) do not have to submit initial notifications.
§ 63.9(b)(3)	No	Section reserved.
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	Yes.	
§ 63.9(g)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit notifications of compliance status.
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) through (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	
§ 63.10(b)(2)(i)	No.	
§ 63.10(b)(2)(ii)	No	See § 63.774(g) for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Yes.	
§ 63.10(b)(2)(iv) through (b)(2)(v)	No.	
§ 63.10(b)(2)(vi) through (b)(2)(xiv)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.10(b)(3)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.
§ 63.10(c)(10) through (11)	No	See § 63.774(g) for recordkeeping of malfunctions.
§ 63.10(c)(12) through (14)	Yes.	
§ 63.10(c)(15)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes	Area sources located outside UA plus offset and UC boundaries do not have to submit performance test reports.
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No	See § 63.775(b)(6) or (c)(6) for reporting of malfunctions.
§ 63.10(e)(1)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(2)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)	Yes	Subpart HH requires major sources to submit Periodic Reports semi-annually. Area sources are required to submit Periodic Reports annually. Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No.	
§ 63.10(e)(3)(i)(D)	Yes	Section reserved.
§ 63.10(e)(3)(ii) through (viii)	Yes.	
§ 63.10(e)(4)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) and (b)	Yes.	
§ 63.11(c), (d), and (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) through (q)	Yes.	
§ 63.15(a) and (b)	Yes.	
§ 63.16	Yes.	

Subpart HHH—[Amended]

■ 23. Section 63.1270 is amended by:
■ a. Revising paragraph (a) introductory text;
■ b. Revising paragraph (a)(4);
■ c. Revising paragraph (b);
■ d. Revising paragraphs (d)(1) and (2); and
■ e. Adding paragraphs (d)(3) and (4).

The revisions and additions read as follows:

§ 63.1270 Applicability and designation of affected source.

(a) This subpart applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants (HAP) emissions as defined in § 63.1271. Emissions for major source determination purposes can be estimated using the maximum natural gas throughput calculated in either paragraph (a)(1) or (2) of this section and paragraphs (a)(3) and (4) of this section. As an alternative to calculating the maximum natural gas throughput, the owner or operator of a new or existing source may use the facility design maximum natural gas throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction in accordance with § 63.10(b)(3). A compressor station that transports natural gas prior to the point of custody transfer or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage source category. A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels (without obtaining and complying with other limitations that keep its potential to emit HAP below major source levels), and becomes a major source, must comply thereafter with all applicable provisions of this subpart starting on the applicable compliance date specified in paragraph (d) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

* * * * *

(4) The owner or operator shall determine the maximum values for other parameters used to calculate potential emissions as the maximum over the same period for which maximum throughput is determined as specified in paragraph (a)(1) or (a)(2) of this section. These parameters shall be based on an annual average or the highest single measured value. For estimating maximum potential emissions from glycol dehydration units, the glycol circulation rate used in the calculation shall be the unit's maximum rate under its physical and

operational design consistent with the definition of potential to emit in § 63.2.

(b) The affected source is each new and existing glycol dehydration unit specified in paragraphs (b)(1) through (3) of this section.

(1) Each large glycol dehydration unit;

(2) Each small glycol dehydration unit for which construction commenced on or before August 23, 2011, is an existing small glycol dehydration unit.

(3) Each small glycol dehydration unit for which construction commenced after August 23, 2011, is a new small glycol dehydration unit.

* * * * *

(d) * * *

(1) Except as specified in paragraphs (d)(3) through (4) of this section, the owner or operator of an affected source, the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with this provisions of the subpart no later than June 17, 2002 except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) Except as specified in paragraphs (d)(3) through (4) of this section, the owner or operator of an affected source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

(3) Each affected small glycol dehydration unit, as defined in § 63.1271, located at a major source, that commenced construction before August 23, 2011, must achieve compliance no later than October 15, 2015, except as provided in § 63.6(i).

(4) Each affected small glycol dehydration unit, as defined in § 63.1271, located at a major source, that commenced construction on or after August 23, 2011, must achieve compliance immediately upon initial startup or October 15, 2012, whichever is later.

* * * * *

■ 24. Section 63.1271 is amended by:

■ a. Adding, in alphabetical order, definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration units,'' ''responsible official'' and ''small glycol dehydration units;'' and

■ b. Revising the definition for ''glycol dehydration unit baseline operations.''

The additions and revision read as follows:

§ 63.1271 Definitions.

* * * * *

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

* * * * *

BTEX means benzene, toluene, ethyl benzene, and xylene.

* * * * *

Flare means a thermal oxidation system using an open flame (*i.e.,* without enclosure).

* * * * *

Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999 and the small glycol dehydration unit operations as of August 23, 2011. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, glycol dehydration unit baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (*i.e.,* at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

* * * * *

Large glycol dehydration unit means a glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 283.0 thousand standard cubic meters per day and actual annual average benzene emissions equal to or greater than 0.90 Mg/yr, determined according to § 63.1282(a). A glycol dehydration unit complying with the 0.9 Mg/yr control option under 63.1275(b)(1)(ii) is considered to be a large dehydrator.

* * * * *

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected sources:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Act or the regulations promulgated thereunder are concerned; and

(ii) The designated representative for any other purposes under part 70.

* * * * *

Small glycol dehydration unit means a glycol dehydration unit, located at a major source, with an actual annual average natural gas flowrate less than 283.0 thousand standard cubic meters per day or actual annual average benzene emissions less than 0.90 Mg/yr, determined according to § 63.1282(a).

* * * * *

■ 25. Section 63.1272 is revised to read as follows:

§ 63.1272 Affirmative defense for violations of emission standards during malfunction.

(a) The provisions set forth in this subpart shall apply at all times.

(b) [Reserved]

(c) [Reserved]

(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed; however, if you fail to meet your burden of proving all of the requirements in the affirmative defense, the affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The violation:

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

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

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

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

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

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

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

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

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

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

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

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

(2) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 26. Section 63.1274 is amended by:

■ a. Revising paragraph (c) introductory text;

■ b. Removing and reserving paragraph (d);

■ c. Revising paragraph (g); and

■ d. Adding paragraph (h).

The revisions and addition read as follows:

§ 63.1274 General standards.

* * * * *

(c) The owner or operator of an affected source (*i.e.,* glycol dehydration unit) located at an existing or new major source of HAP emissions shall comply with the requirements in this subpart as follows:

* * * * *

(d) [Reserved]

* * * * *

(g) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, and a leak is detected, the owner or operator shall take further action as required by the applicable provisions of this subpart.

(h) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

■ 27. Section 63.1275 is amended by:

■ a. Revising paragraph (a);

■ b. Revising paragraph (b)(1);

■ c. Revising paragraph (c)(2); and

■ d. Revising paragraph (c)(3).

The revisions read as follows:

§ 63.1275 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in paragraph (c)(1) of § 63.1274.

(b) * * *

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i) or (iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.1271, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(d).

(ii) The owner or operator of a large glycol dehydration unit shall connect the process vent to a control device or a combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be less than 0.90 megagrams per year. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(d), except that the performance requirements specified in § 63.1281(d)(1)(i) and (ii) do not apply.

(iii) You must limit BTEX emissions from each existing small glycol dehydration unit, as defined in § 63.1271, to the limit determined in Equation 1 of this section. You must limit BTEX emissions from each new small glycol dehydration unit process vent, as defined in § 63.1271, to the limit determined in Equation 2 of this section. The limits determined using Equation 1 or Equation 2, of this section, must be met in accordance with one of the alternatives specified in paragraphs (b)(1)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 3.10x10^{-4} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams} \quad \text{Equation 1}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

3.10×10^{-4} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day;

$C_{i,BTEX}$ = Annual average BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

$$EL_{BTEX} = 5.44x10^{-5} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams} \quad \text{Equation 2}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

5.44×10^{-5} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day;

$C_{i,BTEX}$ = Annual average BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

(A) Connect the process vent to a control device or combination of control devices through a closed-vent system. The closed vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(f).

(B) Meet the emissions limit through process modifications in accordance with the requirements specified in § 63.1281(e).

(C) Meet the emission limit for each small glycol dehydration unit using a combination of process modifications and one or more control devices through the requirements specified in paragraphs (b)(1)(iii)(A) and (B) of this section.

(D) Demonstrate that the emissions limit is met through actual uncontrolled operation of the small glycol dehydration unit. Document operational parameters in accordance with the requirements specified in § 63.1281(e) and emissions in accordance with the requirements specified in § 63.1282(a)(3).

* * * * *

(c) * * *

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.1281(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i) through (iv) through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) For any large glycol dehydration unit, benzene emissions are reduced to a level less than 0.90 megagrams per year.

(iii) For each existing small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated in Equation 1 of paragraph (b)(1)(iii) of this section.

(iv) For each new small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated in Equation 2 of paragraph (b)(1)(iii) of this section.

■ 28. Section 63.1281 is amended by:

■ a. Revising paragraph (c)(1);

■ b. Revising the heading of paragraph (d).

■ c. Adding paragraph (d) introductory text;

■ d. Revising paragraph (d)(1)(i)(C);

■ e. Revising paragraphs (d)(1)(ii) and (iii);

■ f. Revising paragraph (d)(4)(i);

■ g. Revising paragraph (d)(5)(i);

■ h. Revising paragraph (e)(2);

■ i. Revising paragraph (e)(3) introductory text;

■ j. Revising paragraph (e)(3)(ii); and

■ k. Adding paragraph (f).

The revisions and additions read as follows:

§ 63.1281 Control equipment requirements.

* * * * *

(c) * * *

(1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

* * * * *

(d) *Control device requirements for sources except small glycol dehydration units.* Owners and operators of small glycol dehydration units shall comply with the control requirements in paragraph (f) of this section.

(1) * * *

(i) * * *

(C) Operates at a minimum temperature of 760 degrees C, provided the control device has demonstrated, under § 63.1282(d), that combustion zone temperature is an indicator of destruction efficiency.

* * * * *

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.1282(d).

(iii) A flare, as defined in § 63.1271, that is designed and operated in accordance with the requirements of § 63.11(b).

* * * * *

(4) * * *

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the emissions unit or units through the closed vent system to the control device as required under § 63.1275. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

* * * * *

(5) * * *

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the

carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.1284(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.1285(d)(4)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.1285(e)(2)(xi).

* * * * *

(e) * * *

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.1275(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (e)(3)(ii) of this section.

* * * * *

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) *Control device requirements for small glycol dehydration units.* (1) The control device used to meet BTEX the emission limit calculated in § 63.1275(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to meet the levels specified in paragraphs (f)(1)(i)(A) or (B) of this section. If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(A) The mass content of BTEX in the gases vented to the device is reduced as determined in accordance with the requirements of § 63.1282(d).

(B) The concentration of either TOC or total HAP in the exhaust gases at the outlet of the device is reduced to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 63.1282(e).

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.1282(d).

(iii) A flare, as defined in § 63.1271, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.1283(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.1282(e) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

■ 29. Section 63.1282 is amended by:

■ a. Revising paragraph (a) introductory text;
■ b. Revising paragraph (a)(1)(ii);
■ c. Revising paragraph (a)(2);
■ d. Revising paragraph (b)(6)(i);
■ e. Adding paragraph (c);
■ f. Revising paragraph (d) introductory text;
■ g. Revising paragraphs (d)(1)(i) through (v);
■ h. Revising paragraph (d)(2);
■ i. Revising paragraph (d)(3) introductory text;
■ j. Revising paragraph (d)(3)(i)(B);
■ k. Revising paragraph (d)(3)(iii) introductory text;
■ l. Revising paragraph (d)(3)(iv) introductory text;
■ m. Revising paragraph (d)(3)(iv)(C)(*1*);
■ n. Adding paragraphs (d)(3)(v) and (vi);
■ o. Revising paragraph (d)(4) introductory text;
■ p. Revising paragraph (d)(4)(i);
■ q. Revising paragraph (d)(5);
■ r. Revising paragraph (e) introductory text;
■ s. Revising paragraphs (e)(2) and (3);
■ t. Adding paragraphs (e)(4) through (e)(6);
■ u. Revising paragraph (f) introductory text;
■ v. Revising paragraph (f)(1);
■ w. Revising paragraph (f)(2) introductory text;
■ x. Revising paragraph (f)(2)(iii) introductory text, (f)(2)(iii)(A) and (f)(2)(iii)(B);
■ y. Revising paragraph (f)(3); and
■ z. Adding paragraphs (g) and (h).

The revisions and additions read as follows:

§ 63.1282 Test methods, compliance procedures, and compliance demonstrations.

(a) *Determination of glycol dehydration unit flowrate, benzene emissions, or BTEX emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

(1) * * *

(ii) The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

(2) The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (a)(2)(i) or (ii) of this section. Emissions shall be determined either uncontrolled or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene or

BTEX emissions using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement by performing three runs of Method 18 in 40 CFR part 60, appendix A; or ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii); or an equivalent method; and averaging the results of the three runs. Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

(b) * * *

(6) * * *

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the process fluid not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inert gases that are not organic HAP or VOC, the average stream response factor shall be calculated on an inert-free basis.

* * * * *

(c) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph (c) applies to the test procedures for small dehydration units.

(1) If the owner or operator is using a control device to comply with the emission limit in § 63.1275(b)(1)(iii), the requirements of paragraph (d) of this section apply. Compliance is demonstrated using the methods specified in paragraph (e) of this section.

(2) If no control device is used to comply with the emission limit in § 63.1275(b)(1)(iii), the owner or operator must determine the glycol dehydration unit BTEX emissions as specified in paragraphs (c)(2)(i) through (iii) of this section. Compliance is demonstrated if the BTEX emissions determined as specified in paragraphs (c)(2)(i) through (iii) are less than the emission limit calculated using the equation in § 63.1275(b)(1)(iii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the outlet of the glycol dehydration unit process vent. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) The BTEX emissions from the outlet of the glycol dehydration unit process vent shall be determined using the procedures specified in paragraph (d)(3)(v) of this section. As an alternative, the mass rate of BTEX at the outlet of the glycol dehydration unit process vent may be calculated using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and shall be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1). When the BTEX mass rate is calculated for glycol dehydration units using the model GRI–GLYCalc™, all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed.

(d) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) using a performance test as specified in paragraph (d)(3) of this section. Owners or operators using a condenser have the option to use a design analysis as specified in paragraph (d)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (d)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent. Flares shall meet the provisions in paragraph (d)(2) of this section. As an alternative to conducting a performance test under this section for combustion control devices, a control device that can be demonstrated to meet the performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) through a performance test conducted by the manufacturer, as specified in paragraph (g) of this section, can be used.

(1) * * *

(i) Except as specified in paragraph (d)(2) of this section, a flare, as defined in § 63.1271, that is designed and operated in accordance with § 63.11(b);

(ii) Except for control devices used for small glycol dehydration units, a boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) Except for control devices used for small glycol dehydration units, a boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) Except for control devices used for small glycol dehydration units, a boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H, or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) Except for control devices used for small glycol dehydration units, a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O, or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

* * * * *

(2) An owner or operator shall design and operate each flare, as defined in § 63.1271, in accordance with the requirements specified in § 63.11(b) and the compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) the owner or operator shall use the test methods and procedures specified in paragraphs (d)(3)(i) through (v) of this section. The initial and periodic performance tests shall be conducted according to the schedule specified in paragraph (d)(3)(vi) of this section.

(i) * * *

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), or the BTEX emission limit specified in § 63.1275(b)(1)(iii), the sampling site

shall be located at the outlet of the combustion device.

* * * * *

(iii) To determine compliance with the control device percent reduction performance requirement in § 63.1281(d)(1)(i)(A), 63.1281(d)(1)(ii), or 63.1281(e)(3)(ii), the owner or operator shall use either Method 18, 40 CFR part 60, appendix A, or Method 25A, 40 CFR part 60, appendix A; or ASTM D6420–99 (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii); alternatively, any other method or data that have been validated according to the applicable procedures in Method 301 of appendix A of this part may be used. The following procedures shall be used to calculate the percentage of reduction:

* * * * *

(iv) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), the owner or operator shall use either Method 18, 40 CFR part 60, appendix A; or Method 25A, 40 CFR part 60, appendix A; or ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii), to measure either TOC (minus methane and ethane) or total HAP. Alternatively, any other method or data that have been validated according to Method 301 of appendix A of this part, may be used. The following procedures shall be used to calculate parts per million by volume concentration, corrected to 3 percent oxygen:

* * * * *

(C) * * *

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B, 40 CFR part 60, appendix A, ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 63.14) shall be used to determine the oxygen concentration ($\%O_{2d}$). The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

* * * * *

(v) To determine compliance with the BTEX emission limit specified in § 63.1275(b)(1)(iii) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of BTEX (E_o) shall be computed using the equations and procedures specified in paragraphs (d)(3)(v)(B)(*1*) and (*2*) of this section.

(*1*) The following equation shall be used:

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj}M_{oj}\right)Q_o$$

Where:

E_o = Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour.

C_{oj} = Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume.

M_{oj} = Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole.

Q_o = Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C.

n = Number of components in sample.

(*2*) When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (d)(3)(v)(B)(*1*) of this section.

(vi) The owner or operator shall conduct performance tests according to the schedule specified in paragraphs (d)(3)(vi)(A) and (B) of this section.

(A) An initial performance test shall be conducted within 180 days after the compliance date that is specified for each affected source in § 63.1270(d)(3) and (4) except that the initial performance test for existing combustion control devices (*i.e.,* control devices installed on or before August 23, 2011) at major sources shall be conducted no later than October 15, 2015. If the owner or operator of an existing combustion control device at a major source chooses to replace such device with a control device whose model is tested under § 63.1282(g), then the newly installed device shall comply with all provisions of this subpart no later than October 15, 2015. The performance test results shall be submitted in the Notification of Compliance Status Report as required in § 63.1285(d)(1)(ii).

(B) Periodic performance tests shall be conducted for all control devices required to conduct initial performance tests except as specified in paragraphs (e)(3)(vi)(B)(*1*) and (*2*) of this section. The first periodic performance test shall be conducted no later than 60 months after the initial performance test required in paragraph (d)(3)(vi)(A) of this section. Subsequent periodic performance tests shall be conducted at intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit. The periodic performance test results must be submitted in the next Periodic Report as specified in § 63.1285(e)(2)(x). Combustion control devices meeting the criteria in either paragraph (e)(3)(vi)(B)(*1*) or (*2*) of this section are not required to conduct periodic performance tests.

(*1*) A control device whose model is tested under, and meets the criteria of, § 63.1282(g), or

(*2*) A combustion control device demonstrating during the performance test under § 63.1282(d) that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 degrees C.

(4) For a condenser design analysis conducted to meet the requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1), the owner or operator shall meet the requirements specified in paragraphs (d)(4)(i) and (ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.1285(d)(1)(i).

(i) The condenser design analysis shall include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the condenser design analysis, an owner or operator may elect to use the procedures specified in paragraph (d)(5) of this section.

* * * * *

(5) As an alternative to the procedures in paragraph (d)(4)(i) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions,'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(e) *Compliance demonstration for control devices performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), and (f)(1). Compliance shall be demonstrated using the requirements in paragraphs (e)(1) through (3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.1281(d)(1)(ii), (e)(3)(ii), or (f)(1) may demonstrate compliance according to paragraph (f) of this section. An owner or operator may switch between compliance with paragraph (e) of this section and compliance with paragraph (f) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.1285(e), following the change.

* * * * *

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.1283(d)(4) except that the inlet gas flowrate to the control device shall not be averaged.

(3) Compliance is achieved when the daily average of the monitoring parameter value calculated under paragraph (e)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (e)(1) of this section. For inlet gas flowrate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.1282(g) or under the performance test conducted under § 63.1282(d), as applicable.

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS required in § 63.1283(d) must be operated at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(5) Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

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

(f) *Compliance demonstration with percent reduction or emission limit performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.1281(d)(1)(ii), (e)(3) or (f)(1) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (f)(1) through (f)(3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to the procedures specified in § 63.1283(d)(5)(ii). For sources required to meet the BTEX limit in accordance with § 63.1281(e) or (f)(1) the owner or operator shall identify the minimum percent reduction necessary to meet the BTEX limit.

(2) Compliance with the percent reduction requirement in § 63.1281(d)(1)(ii), (e)(3), or (f)(1) shall be demonstrated by the procedures in paragraphs (f)(2)(i) through (iii) of this section.

* * * * *

(iii) Except as provided in paragraphs (f)(2)(iii)(A), (B), and (D) of this section, at the end of each operating day the owner or operator shall calculate the 30-day average HAP, or BTEX, emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (f)(2)(ii) of this section for the preceding 30 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.1281(e), the 30-day average HAP emission, or BTEX, emission reduction, shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency as determined in paragraph (f)(2)(ii) of this section, both for the preceding 30 operating days.

(A) After the compliance date specified in § 63.1270(d), an owner or operator of a facility that stores natural gas that has less than 30 days of data for determining the average HAP, or BTEX, emission reduction, as appropriate, shall calculate the cumulative average at the end of the withdrawal season, each season, until 30 days of condenser operating data are accumulated. For a facility that does not store natural gas, the owner or operator that has less than 30 days of data for determining average HAP, or BTEX, emission reduction, as appropriate, shall calculate the cumulative average at the end of the calendar year, each year, until 30 days of condenser operating data are accumulated.

(B) After the compliance date specified in § 63.1270(d), for an owner or operator that has less than 30 days of data for determining the average HAP, or BTEX, emission reduction, as appropriate, compliance is achieved if the average HAP, or BTEX, emission reduction, as appropriate, calculated in paragraph (f)(2)(iii)(A) of this section is equal to or greater than 95.0 percent or is equal to or greater than the minimum percent reduction necessary to meet the BTEX emission limit as determined in paragraph (f)(1) of this section.

* * * * *

(3) Compliance is achieved based on the applicable criteria in paragraphs (f)(3)(i) or (ii) of this section.

(i) For sources meeting the HAP emission reduction specified in § 63.1281(d)(1)(ii) or (e)(3) if the average HAP emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than 95.0 percent.

(ii) For sources required to meet the BTEX limit under § 63.1281(e)(3) or (f)(1), compliance is achieved if the average BTEX emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than the minimum percent reduction identified in paragraph (f)(1) of this section.

(g) *Performance testing for combustion control devices—manufacturers' performance test.*

(1) This paragraph (g) applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer shall demonstrate that a specific model of control device achieves the performance requirements in (g)(7) of this section by conducting a performance test as specified in paragraphs (g)(2) through (6) of this section.

(2) Performance testing shall consist of three one-hour (or longer) test runs for each of the four following firing rate settings making a total of 12 test runs per test. Propene (propylene) gas shall be used for the testing fuel. All fuel analyses shall be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures shall be tested simultaneously and with all burners operational. Results shall be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data shall be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. Data shall be submitted with the test report in accordance with paragraph (g)(8)(iii) of this section.

(4) Inlet testing shall be conducted as specified in paragraphs (g)(4)(i) through (iii) of this section.

(i) The inlet gas flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure inlet gas flowrate at the control device inlet location. The fitting for filling fuel sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet gas flowrate shall be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the inlet gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet gas sampling shall be conducted in accordance with the criteria in paragraphs (g)(4)(iii)(A) and (B) of this section.

(A) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3 hour period. Filling shall be conducted as specified in the following:

(*1*) Open the canister sampling valve at the beginning of the total hydrocarbon (THC) test, and close the canister at the end of each THC test run.

(*2*) Fill one canister across the three test runs for each THC test such that one composite fuel sample exists for each test condition.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each inlet gas sample shall be analyzed using the following methods. The results shall be included in the test report.

(*1*) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*3*) Higher heating value using ASTM D3588–98 (Reapproved 2003) or ASTM D4891–89 (Reapproved 2006) (incorporated by reference as specified in § 63.14).

(5) Outlet testing shall be conducted in accordance with the criteria in paragraphs (g)(5)(i) through (v) of this section.

(i) Sampling and flowrate measured in accordance with the following:

(A) The outlet sampling location shall be a minimum of 4 equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports shall be used.

(B) Flowrate shall be measured using Method 1, 40 CFR part 60, Appendix 1, for determining flow measurement traverse point location; and Method 2, 40 CFR part 60, Appendix 1, shall be used to measure duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer or other pressure measurement device shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (g)(4)(iii)(B), and (g)(5)(ii)(A) and (B) of this section.

(A) An integrated bag sample shall be collected during the Method 4, 40 CFR part 60, Appendix A, moisture test. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the following criteria:

(*1*) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(*2*) The sampling line shall be purged with stack gas before opening the valve and beginning to fill the bag.

(*3*) The bag contents shall be vigorously mixed prior to the GC analysis.

(*4*) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, Appendix A, shall be modified by using EPAAlt–045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, the initial calibration using at least three concentration levels shall be repeated.

(B) Report the molecular weight of: O_2, CO_2, methane (CH4), and N_2 and include in the test report submitted under § 63.775(d)(iii). Moisture shall be determined using Method 4, 40 CFR part 60, Appendix A. Traverse both ports with the Method 4, 40 CFR part 60, Appendix A, sampling train during each test run. Ambient air shall not be

introduced into the Method 3C, 40 CFR part 60, Appendix A, integrated bag sample during the port change.

(iii) Carbon monoxide shall be determined using Method 10, 40 CFR part 60, Appendix A or ASTM D6522–00 (Reapproved 2005) (incorporated by reference as specified in § 63.14). The test shall be run at the same time and with the sample points used for the EPA Method 25A, 40 CFR part 60, Appendix A, testing. An instrument range of 0–10 per million by volume-dry (ppmvd) shall be used.

(iv) Visible emissions shall be determined using Method 22, 40 CFR part 60, Appendix A. The test shall be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(v) Excess air shall be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, Appendix A, equation 3B–1 or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 63.14).

(6) Total hydrocarbons (THC) shall be determined as specified by the following criteria:

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, Appendix A, except the option for locating the probe in the center 10 percent of the stack shall not be allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during the test run.

(ii) A valid test shall consist of three Method 25A, 40 CFR part 60, Appendix A, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements shall be reported in terms of ppmvw as propane.

(vi) THC results shall be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, Appendix A.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(7) Performance test criteria:

(i) The control device model tested must meet the criteria in paragraphs (g)(7)(i)(A) through (C) of this section:

(A) Method 22, 40 CFR part 60, Appendix A, results under paragraph (g)(5)(v) of this section with no indication of visible emissions, and

(B) Average Method 25A, 40 CFR part 60, Appendix A, results under paragraph (g)(6) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2, and

(C) Average CO emissions determined under paragraph (g)(5)(iv) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess combustion air shall be equal to or greater than 150 percent.

(ii) The manufacturer shall determine a maximum inlet gas flowrate which shall not be exceeded for each control device model to achieve the criteria in paragraph (g)(7)(i) of this section.

(iii) A control device meeting the criteria in paragraph (g)(7)(i)(A) through (C) of this section will have demonstrated a destruction efficiency of 95.0 percent for HAP regulated under this subpart.

(8) The owner or operator of a combustion control device model tested under this section shall submit the information listed in paragraphs (g)(8)(i) through (iii) in the test report required under § 63.775(d)(1)(iii).

(i) Full schematic of the control device and dimensions of the device components.

(ii) Design net heating value (minimum and maximum) of the device.

(iii) Test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flowrate.

(iv) Air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (g)(8)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flowrate.

(O) Wind velocity and direction.

(vi) The test report shall include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values.

(h) *Compliance demonstration for combustion control devices—manufacturers' performance test.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (g) of this section. Owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1), (e)(3)(ii) or (f)(1), by installing a device tested under paragraph (g) of this section and complying with the following criteria:

(1) The inlet gas flowrate shall meet the range specified by the manufacturer. Flowrate shall be calculated as specified in § 63.1283(d)(3)(i)(H)(*1*).

(2) A pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with § 63.1283(d)(3)(i)(H)(*2*).

(3) Devices shall be operated with no visible emissions, except for periods not to exceed a total of 2 minutes during any hour. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed each calendar quarter. The observation period shall be 1 hour and shall be conducted according to EPA Method 22, 40 CFR part 60, Appendix A.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flowrate monitored under paragraph (h)(1) of this section is equal to or below the maximum established by the manufacturer; and

(ii) The pilot flame is present at all times; and

(iii) During the visible emissions test performed under paragraph (h)(3) of this section the duration of visible emissions does not exceed a total of 2 minutes during the observation period. Devices failing the visible emissions test shall follow manufacturers repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit shall be recorded in a maintenance and repair log and shall be available on site for inspection.

(iv) Following return to operation from maintenance or repair activity, each device must pass a Method 22 visual observation as described in paragraph (h)(3) of this section.

■ 30. Section 63.1283 is amended by:
■ a. Adding paragraph (b);
■ b. Revising paragraph (d)(1) introductory text;
■ c. Revising paragraph (d)(1)(ii) and adding paragraphs (d)(1)(iii) and (iv);
■ d. Revising paragraph (d)(2);
■ e. Revising paragraph (d)(3)(i)(A);
■ f. Revising paragraph (d)(3)(i)(D);
■ g. Revising paragraph (d)(3)(i)(G);
■ h. Adding paragraph (d)(3)(i)(H);
■ i. Revising paragraph (d)(4);
■ j. Revising paragraph (d)(5)(i);
■ k. Revising paragraphs (d)(5)(ii)(A) through (C);
■ l. Revising paragraph (d)(6) introductory text;
■ m. Revising paragraph (d)(6)(ii);
■ n. Adding paragraph (d)(6)(v);
■ o. Revising paragraph (d)(7); and
■ p. Removing and reserving paragraph (d)(8).

The additions and revisions read as follows:

§ 63.1283 Inspection and monitoring requirements.

* * * * *

(b) The owner or operator of a control device whose model was tested under 63.1282(g) shall develop an inspection and maintenance plan for each control device. At a minimum, the plan shall contain the control device manufacturer's recommendations for ensuring proper operation of the device. Semi-annual inspections shall be conducted for each control device with maintenance and replacement of control device components made in accordance with the plan.

* * * * *

(d) *Control device monitoring requirements.* (1) For each control device except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (7) of this section. Owners or operators that install and operate a flare in accordance with § 63.1281(d)(1)(iii) or (f)(1)(iii) are exempt from the requirements of paragraphs (d)(4) and (5) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.1281(d), (e)(3), or (f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

* * * * *

(ii) A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph (d) of this section and in § 63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in your approved site-specific monitoring plan. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (d)(1)(ii)(A) through (E) of this section in your site-specific monitoring plan.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(B) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements;

(C) Equipment performance checks, system accuracy audits, or other audit procedures;

(D) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (c)(3); and

(E) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(iii) The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(iv) The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

(2) An owner or operator is exempted from the monitoring requirements specified in paragraphs (d)(3) through (7) of this section for the following types of control devices:

(i) Except for control devices for small glycol dehydration units, a boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel;

(ii) Except for control devices for small glycol dehydration units, a boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) * * *

(i) * * *

(A) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 63.1282(d) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(D) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.1282(d)(3) and shall be based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device whose model is tested under § 63.1282(g):

(*1*) The owner or operator shall determine actual average inlet waste gas flowrate using the model GRI–GLYCalc™, Version 3.0 or higher, ProMax, or AspenTech HYSYS. Inputs to the models shall be representative of actual operating conditions of the controlled unit. The determination shall be performed to coincide with the visible emissions test under § 63.1282(h)(3);

(*2*) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

* * * * *

(4) Using the data recorded by the monitoring system, except for inlet gas flowrate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) * * *

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to

define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer's recommendations or a combination of both.

(B) If the owner or operator uses a condenser design analysis in accordance with the requirements of § 63.1282(d)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the condenser design analysis and may be supplemented by the condenser manufacturer's recommendations.

(C) If the owner or operator operates a control device where the performance test requirement was met under § 63.1282(g) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii) or (f)(1), then the maximum inlet gas flowrate shall be established based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(ii) * * *

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.1282(d)(4)(i) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraph (d)(5)(ii)(B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(6) An excursion for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (d)(6)(i) through (d)(6)(v) of this section being met. When multiple operating parameters are monitored for the same control device and during the same operating day, and more than one of these operating parameters meets an excursion criterion specified in paragraphs (d)(6)(i) through (d)(6)(v) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

* * * * *

(ii) For sources meeting § 63.1281(d)(1)(ii), an excursion occurs when average condenser efficiency calculated according to the requirements specified in § 63.1282(f)(2)(iii) is less than 95.0 percent, as specified in § 63.1282(f)(3). For sources meeting § 63.1281(f)(1), an excursion occurs when the 30-day average condenser efficiency calculated according to the requirements of § 63.1282(f)(2)(iii) is less than the identified 30-day required percent reduction.

* * * * *

(v) For control device whose model is tested under § 63.1282(g) an excursion occurs when:

(A) The inlet gas flowrate exceeds the maximum established during the test conducted under § 63.1282(g).

(B) Failure of the quarterly visible emissions test conducted under § 63.1282(h)(3) occurs.

(7) For each excursion, the owner or operator shall be deemed to have failed to have applied control in a manner that achieves the required operating parameter limits. Failure to achieve the required operating parameter limits is a violation of this standard.

(8) [Reserved]

* * * * *

■ 31. Section 63.1284 is amended by:

■ a. Revising paragraph (b)(3) introductory text;

■ b. Removing and reserving paragraph (b)(3)(ii);

■ c. Revising paragraph (b)(4)(ii);

■ d. Revising paragraph (b)(4)(iii);

■ e. Adding paragraph (b)(7)(ix); and

■ f. Adding paragraphs (f), (g) and (h).

The revisions and additions read as follows:

§ 63.1284 Recordkeeping requirements.

* * * * *

(b) * * *

(3) Records specified in § 63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of § 63.1283(d). Notwithstanding the previous sentence, monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

* * * * *

(ii) [Reserved]

* * * * *

(4) * * *

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.1283(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section.

(A) For flares, the records required in paragraph (e) of this section.

(B) For condensers installed to comply with § 63.1275, records of the annual 30-day rolling average condenser efficiency determined under § 63.1282(f) shall be kept in addition to the daily averages.

(C) For a control device whose model is tested under § 63.1282(g), the records required in paragraph (g) of this section.

(iii) Hourly records of the times and durations of all periods when the vent stream is diverted from the control device or the device is not operating.

* * * * *

(7) * * *

(ix) Records identifying the carbon replacement schedule under § 63.1281(d)(5) and records of each carbon replacement.

* * * * *

(f) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of

operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.1274(h), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(g) Record the following when using a control device whose model is tested under § 63.1282(g) to comply with § 63.1281(d), (e)(3)(ii) and (f)(1):

(1) All visible emission readings and flowrate calculations made during the compliance determination required by § 63.1282(h); and

(2) All hourly records and other recorded periods when the pilot flame is absent.

(h) The date the semi-annual maintenance inspection required under § 63.1283(b) is performed. Include a list of any modifications or repairs made to the control device during the inspection and other maintenance performed such as cleaning of the fuel nozzles.

■ 32. Section 63.1285 is amended by:
■ a. Revising paragraph (b)(1);
■ b. Revising paragraph (b)(6);
■ c. Removing paragraph (b)(7);
■ d. Revising paragraph (d) introductory text;
■ e. Revising paragraph (d)(1) introductory text;
■ f. Revising paragraph (d)(1)(i);
■ g. Revising paragraph (d)(1)(ii) introductory text;
■ h. Revising paragraph (d)(2) introductory text;
■ i. Revising paragraph (d)(4) introductory text;
■ j. Revising paragraph (d)(4)(ii);
■ k. Adding paragraph (d)(4)(iv);
■ l. Revising paragraph (d)(10);
■ m. Adding paragraphs (d)(11) and (d)(12);
■ n. Revising paragraph (e)(2) introductory text;
■ o. Revising paragraph (e)(2)(ii)(B);
■ p. Adding paragraphs (e)(2)(ii)(D) and (E);
■ q. Adding paragraphs (e)(2)(x) through (xiii); and
■ r. Adding paragraph (g).

The revisions and additions read as follows:

§ 63.1285 Reporting requirements.

* * * * *

(b) * * *

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted as provided in paragraphs (b)(1)(i) and (ii) of this section.

(i) Except as otherwise provided in paragraph (b)(1)(ii) of this section, the initial notification shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000 and plan to be area sources by June 17, 2002 shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(ii) An affected source identified under § 63.1270(d)(3) shall submit an initial notification required for existing affected sources under § 63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by October 15, 2013, whichever is later. An affected source identified under § 63.1270(d)(3) that plans to be an area source by October 15, 2015, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.1274(h), including actions taken to correct a malfunction.

* * * * *

(d) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status Report as required under § 63.9(h) within 180 days after the compliance date specified in § 63.1270(d). In addition to the information required under § 63.9(h), the Notification of Compliance Status Report shall include the information specified in paragraphs (d)(1) through (12) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If all of the information required under this paragraph have been submitted at any time prior to 180 days after the applicable compliance dates specified in § 63.1270(d), a separate Notification of Compliance Status Report is not required. If an owner or operator submits the information specified in paragraphs (d)(1) through (12) of this section at different times, and/or different submittals, subsequent submittals may refer to previous submittals instead of duplicating and resubmitting the previously submitted information.

(1) If a closed-vent system and a control device other than a flare are used to comply with § 63.1274, the owner or operator shall submit the information in paragraph (d)(1)(iii) of this section and the information in either paragraph (d)(1)(i) or (ii) of this section.

(i) The condenser design analysis documentation specified in § 63.1282(d)(4) of this subpart if the owner or operator elects to prepare a design analysis; or

(ii) If the owner or operator is required to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.1282(d)(3), and that the test conditions are representative of current operating conditions. If the owner or operator operates a combustion control device model tested under § 63.1282(g), an electronic copy of the performance test results shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/.*

* * * * *

(2) If a closed-vent system and a flare are used to comply with § 63.1274, the owner or operator shall submit performance test results including the information in paragraphs (d)(2)(i) and (ii) of this section. The owner or operator shall also submit the information in paragraph (d)(2)(iii) of this section.

* * * * *

(4) For each control device other than a flare used to meet the requirements of § 63.1274, the owner or operator shall submit the information specified in paragraphs (d)(4)(i) through (iv) of this section for each operating parameter required to be monitored in accordance with the requirements of § 63.1283(d).

* * * * *

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.1283(d)(5) of this subpart. This explanation shall include

any data and calculations used to develop the value, and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1).

* * * * *

(iv) For each carbon adsorber, the predetermined carbon replacement schedule as required in § 63.1281(d)(5)(i).

* * * * *

(10) The owner or operator shall submit the analysis prepared under § 63.1281(e)(2) to demonstrate that the conditions by which the facility will be operated to achieve the HAP emission reduction of 95.0 percent, or the BTEX limit in § 63.1275(b)(1)(iii) through process modifications or a combination of process modifications and one or more control devices.

(11) If the owner or operator installs a combustion control device model tested under the procedures in § 63.1282(g), the data listed under § 63.1282(g)(8).

(12) For each combustion control device model tested under § 63.1282(g), the information listed in paragraphs (d)(12)(i) through (vi) of this section.

(i) Name, address and telephone number of the control device manufacturer.

(ii) Control device model number.

(iii) Control device serial number.

(iv) Date the model of control device was tested by the manufacturer.

(v) Manufacturer's HAP destruction efficiency rating.

(vi) Control device operating parameters, maximum allowable inlet gas flowrate.

* * * * *

(e) * * *

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (xiii) of this section, as applicable.

* * * * *

(ii) * * *

(B) For each excursion caused when the 30-day average condenser control efficiency is less than the value, as specified in § 63.1283(d)(6)(ii), the report must include the 30-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

* * * * *

(D) For each excursion caused when the maximum inlet gas flowrate identified under § 63.1282(g) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

(E) For each excursion caused when visible emissions determined under § 63.1282(h) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred, repairs affected to the unit, and date the unit was returned to service.

* * * * *

(x) The results of any periodic test as required in § 63.1282(d)(3) conducted during the reporting period.

(xi) For each carbon adsorber used to meet the control device requirements of § 63.1281(d)(1), records of each carbon replacement that occurred during the reporting period.

(xii) For combustion control device inspections conducted in accordance with § 63.1283(b) the records specified in § 63.1284(h).

(xiii) Certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

* * * * *

(g) *Electronic reporting.* (1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX)(*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(2) All reports required by this subpart not subject to the requirements in paragraph (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.,* by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (g)(1) of this section in paper format.

■ 33. Section 63.1287 is amended by revising paragraph (a) to read as follows:

§ 63.1287 Alternative means of emission limitation.

(a) If, in the judgment of the Administrator, an alternative means of emission limitation will achieve a reduction in HAP emissions at least equivalent to the reduction in HAP emissions from that source achieved under the applicable requirements in §§ 63.1274 through 63.1281, the Administrator will publish a notice in the **Federal Register** permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

* * * * *

■ 34. Appendix to Subpart HHH of Part 63—Table is amended by revising Table 2 to read as follows:

Appendix to Subpart HHH of Part 63—Tables

* * * * *

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6) through (a)(8)	Yes.	
§ 63.1(a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12)	Yes.	
§ 63.1(b)(1)	No	Subpart HHH specifies applicability.
§ 63.1(b)(2)	Yes.	
§ 63.1(b)(3)	No.	
§ 63.1(c)(1)	No	Subpart HHH specifies applicability.
§ 63.1(c)(2)	No.	
§ 63.1(c)(3)	No	Section reserved.
§ 63.1(c)(4)	Yes.	
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HHH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1)	Yes.	
§ 63.4(a)(2)	Yes.	
§ 63.4(a)(3)	No	Section reserved.
§ 63.4(a)(4)	No	Section reserved.
§ 63.4(a)(5)	No	Section reserved.
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	No	Preconstruction review required only for major sources that commence construction after promulgation of the standard.
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	No	Section reserved.
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) and (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)	Yes.	
§ 63.6(e)	Yes	Except as otherwise specified.
§ 63.6(e)(1)(i)	No	See § 63.1274(h) for general duty requirement.
§ 63.6(e)(1)(ii)	No.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	No	Section reserved.
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.6(h)(1)	No.	
§ 63.6(h)(2)	Yes.	
§ 63.6(h)(3)	No	Section reserved.
§ 63.6(h)(4) through (h)(9)	Yes.	
§ 63.6(i)(1) through (i)(14)	Yes.	
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(a)(4)	Yes.	
§ 63.7(b)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	Yes.	
§ 63.8(c)(1)(i)	No.	
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	No.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	No.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)(1)	Yes.	
§ 63.8(d)(2)	Yes.	
§ 63.8(d)(3)	Yes	Except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.8(e)	Yes	Subpart HHH does not specifically require continuous emissions monitor performance evaluations, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	No	Subpart HHH does not require continuous emissions monitoring.
§ 63.8(g)	No	Subpart HHH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification.
§ 63.9(b)(3)	No	Section reserved.
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	Yes.	
§ 63.9(g)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes.	
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) and (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes	Section 63.1284(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.10(b)(2)(i)	No.	
§ 63.10(b)(2)(ii)	No	See § 63.1284(f) for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Yes.	
§ 63.10(b)(2)(iv) through (b)(2)(v)	No.	
§ 63.10(b)(2)(vi) through (b)(2)(xiv)	Yes.	
§ 63.10(b)(3)	No.	
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.
§ 63.10(c)(10) through (c)(11)	No	See § 63.1284(f) for recordkeeping of malfunctions.
§ 63.10(c)(12) through (c)(14)	Yes.	
§ 63.10(c)(15)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes.	
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No	See § 63.1285(b)(6) for reporting of malfunctions.
§ 63.10(e)(1)	Yes.	
§ 63.10(e)(2)	Yes.	
§ 63.10(e)(3)(i)	Yes	Subpart HHH requires major sources to submit Periodic Reports semi-annually.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No	Section reserved.
§ 63.10(e)(3)(i)(D)	Yes.	
§ 63.10(e)(3)(ii) through (e)(3)(viii)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) through (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) through (q)	Yes.	
§ 63.15(a) and (b)	Yes.	

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EPA-APPROVED VIRGINIA REGULATIONS AND STATUTES—Continued

State citation	Title/Subject	State effective date	EPA approval date	Explanation [former SIP citation]
*	*	*	*	*
Article 43 Municipal Solid Waste Landfills (Rule 4–43)				
*	*	*	*	*
5–40–5810	Definitions	8/17/11	6/1/12 by Letter Notice	The SIP effective date is 6/1/12.
5–40–5820	Standard for air emissions	8/17/11	6/1/12 by Letter Notice	The SIP effective date is 6/1/12.
*	*	*	*	*
5–140–5850	Compliance	8/17/11	6/1/12 by Letter Notice	The SIP effective date is 6/1/12.
*	*	*	*	*
5–40–5880	Reporting	8/17/11	6/1/12 by Letter Notice	The SIP effective date is 6/1/12.
*	*	*	*	*
5–40–5920	Permits	8/17/11	6/1/12 by Letter Notice	The SIP effective date is 6/1/12.
*	*	*	*	*
9 VAC 5, Chapter 130 Regulations for Open Burning [Formerly 9VAC5 Chapter 40, Part II, Article 40]				
Part I General Provisions				
*	*	*	*	*
5–130–20	Definitions	8/17/11	6/1/12 by Letter Notice	The SIP effective date is 6/1/12.
*	*	*	*	*
5–130–40	Permissible open burning	8/17/11	6/1/12 by Letter Notice	The SIP effective date is 6/1/12.
*	*	*	*	*

* * * * *

[FR Doc. 2012–22207 Filed 9–10–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2007–0544; FRL–9684–7]

RIN 2060–AQ41

National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes the residual risk and technology review conducted for the pulp and paper industry source category regulated under national emission standards for hazardous air pollutants. The EPA is required to conduct residual risk and technology reviews under the Clean Air Act. This action finalizes amendments to the national emission standards for hazardous air pollutants that include a requirement for 5-year repeat emissions testing for selected process equipment; revisions to provisions addressing periods of startup, shutdown and malfunction; a requirement for electronic reporting; additional test methods for measuring methanol emissions; and technical and editorial changes. The amendments are expected to ensure that control systems are properly maintained over time, ensure continuous compliance with standards and improve data accessibility; we estimate facilities nationwide will spend $2.1 million per year to comply.

DATES: This final action is effective on September 11, 2012. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of September 11, 2012.

ADDRESSES: The EPA has established a docket for this action under Docket ID Number EPA–HQ–OAR–2007–0544. 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, contact Mr. John Bradfield, Office of Air Quality Planning and Standards, (E143–03), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–3062; fax number: (919) 541–3470; and email address: *bradfield.john@epa.gov.*

SUPPLEMENTARY INFORMATION: For specific information regarding the risk modeling methodology, contact Mr. James Hirtz, Health and Environmental Impacts Division (C539–02), Office of

Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0881; fax number: (919) 541–0840; and email address: *hirtz.james@epa.gov.* For information about the applicability of the national emission standards for hazardous air pollutants 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 FINAL ACTION

NESHAP for:	OECA Contact[1]	OAQPS Contact[2]
Pulp and Paper.	Sara Ayres, (202) 564–5391, *ayres.sara@epa.gov.*	John Bradfield, (919) 541–3062, *bradfield.john@epa.gov.*

[1] EPA's Office of Enforcement and Compliance Assurance.
[2] EPA's Office of Air Quality Planning and Standards.

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

ANSI American National Standards Institute
ASME American Society of Mechanical Engineers
ASTM American Society for Testing and Materials
CAA Clean Air Act
CBI Confidential Business Information
CCA Clean Condensate Alternative
CDX EPA's Central Data Exchange
CEDRI EPA's Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CWA Clean Water Act
DC District of Columbia
DC Cir. United States Court of Appeals for the District of Columbia Circuit
EIA Economic Impact Analysis
EJ Environmental Justice
EPA Environmental Protection Agency
ERT Electronic Reporting Tool
FR **Federal Register**
FTIR Fourier Transform Infrared
HAP Hazardous Air Pollutants
HVLC High Volume Low Concentration
IBR Incorporation by Reference
ICR Information Collection Request
km Kilometer
LVHC Low Volume High Concentration
MACT Maximum Achievable Control Technology
MACT Code Code within the NEI used to identify processes included in a source category
MIR Maximum Individual Risk
NAICS North American Industry Classification System
NCASI National Council for Air and Stream Improvement
NEI National Emissions Inventory
NESHAP National Emissions Standards for Hazardous Air Pollutants
NRDC Natural Resources Defense Council
NTTAA National Technology Transfer and Advancement Act of 1995
NW Northwest
OAQPS EPA's Office of Air Quality Planning and Standards
ODTP Oven-Dried Ton of Pulp
OECA EPA's Office of Enforcement and Compliance Assurance
OMB Office of Management and Budget
O&M Operations and Maintenance
ppmw Parts Per Million by Weight
PRA Paperwork Reduction Act
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RTR Residual Risk and Technology Review
S. Ct. United States Supreme Court
SBA Small Business Administration
SISNOSE Significant Economic Impact on a Substantial Number of Small Entities
SSM Startup, Shutdown, and Malfunction the Court United State Court of Appeals for the District of Columbia Circuit
TOSHI Target Organ-Specific Hazard Index
tpy Tons Per Year
TTN EPA's Technology Transfer Network
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
U.S.C. United States Code
VCS Voluntary Consensus Standards
WWW Worldwide Web
yr Year

Background Information Document. On December 27, 2011 (76 FR 81328), the EPA proposed revisions to the pulp and paper industry NESHAP based on evaluations performed by the EPA in order to conduct our RTR. In this action, we are finalizing decisions and revisions for the rule. A summary of the public comments on the proposal and the EPA's responses to those comments is available in Docket ID Number EPA–HQ–OAR–2007–0544. *Organization of this Document.* The following outline is provided to aid in locating information in the preamble.

I. General Information
A. Executive Summary
B. Does this action apply to me?
C. Where can I get a copy of this document?
D. Judicial Review
II. Background
III. Summary of the Final Rule
A. What are the final rule amendments for the pulp and paper industry source category?
B. What are the requirements during periods of startup, shutdown and malfunction?
C. What are the effective and compliance dates of the standards?
D. What are the requirements for submission of performance test data to the EPA?
IV. Summary of Significant Changes Since Proposal
A. Changes to the Risk Assessment Performed under CAA Section 112(f)
B. Changes to the Technology Review Performed under CAA Section 112(d)(6)
C. Other Changes Since Proposal
V. Summary of Cost, Environmental and Economic Impacts
A. What are the affected facilities?
B. What are the air quality impacts?
C. What are the cost impacts?
D. What are the economic impacts?
E. What are the benefits?
VI. Statutory and Executive Order Reviews
A. Executive Orders 12866: Regulatory Planning and Review, and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

Section 112(f)(2) of the CAA requires us to determine for source categories subject to MACT standards, whether the MACT emissions standards provide an ample margin of safety to protect public health. This review, known as the residual risk review—is a one-time review that must occur within 8 years of issuance of the MACT standard. Section 112(d)(6) of the CAA requires the EPA to review and revise section 112 emissions standards, as necessary, taking into account developments in practices, processes and control technologies, emission standards promulgated under section 112 no less often than every 8 years. We issued the NESHAP for the pulp and paper industry (40 CFR part 63, subpart S) in 1998 and are due for review under CAA sections 112(d)(6) and 112(f)(2). In addition to conducting the RTR for subpart S, we are evaluating the SSM

provisions in the rule in light of the D.C. Circuit Court of Appeals decision in *Sierra Club* v. *EPA*, 551 F.3d 1019 (D.C. Cir. 2008). As explained below, in the *Sierra Club* case, the D.C. Circuit vacated the SSM exemption provisions in the General Provisions for non-opacity and opacity standards.

To address the RTR assessments and SSM exemptions, proposed amendments to subpart S were developed, signed by the EPA Administrator on December 15, 2011, and published in the **Federal Register** on December 27, 2011. A 60-day period ending February 27, 2012, was provided for the public to submit comments on the proposal to the EPA. This action addresses the public comments on the proposal and finalizes the amendments to subpart S. The amendments are expected to ensure that control systems are properly maintained over time, ensure continuous compliance with standards and improve data accessibility.

2. Summary of Major Provisions

As part of an ongoing effort to improve compliance with various federal air emission regulations, we are requiring repeat air emissions performance testing once every 5 years for facilities complying with the standards for kraft, soda and semi-chemical pulping vent gases; sulfite pulping processes; and bleaching systems. We are also finalizing changes to the subpart S NESHAP and the General Provisions applicability table to eliminate the SSM exemption. To increase the ease and efficiency of data submittal and improve data accessibility, we are requiring mills to submit electronic copies of performance test reports to the EPA's WebFIRE database. To allow mills greater flexibility in demonstrating compliance with emission limits for total HAP measured as methanol, we are including four additional test methods for measuring methanol emissions from pulp and paper processes, as alternatives to EPA Method 308. We are also making a number of technical and editorial changes, including clarifying the location in the CFR of applicable test methods, incorporating by reference several non-EPA test methods and revising the General Provisions applicability table to align with those sections of the General Provisions that have been amended or reserved over time.

3. Costs and Benefits

Table 2 summarizes the costs and benefits of this action. See section V of this preamble for further discussion.

TABLE 2—SUMMARY OF THE COSTS AND BENEFITS OF THE FINAL AMENDMENTS TO THE NESHAP FOR THE PULP AND PAPER INDUSTRY

Requirement	Capital cost [million]	Annual cost [million]	Net benefit
Repeat emissions testing	$5.4	$1.3	N/A
Incremental reporting/record-keeping	0.50	0.74	N/A
Total nationwide	5.9	2.1	N/A

B. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action are shown in Table 3 of this preamble.

TABLE 3—NESHAP AND INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

NESHAP and source category	NAICS Code [1]	MACT Code [2]
Pulp and Paper (Subpart S)	322	1626–1

[1] North American Industry Classification System.
[2] Maximum Achievable Control Technology.

Table 3 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 pulp and paper production source category includes any facility engaged in the production of pulp and/or paper.[1] This category includes, but is not limited to, integrated mills (where pulp and paper or paperboard are manufactured on-site), non-integrated mills (where either pulp or paper/paperboard are manufactured on-site, but not both), and secondary fiber mills (where waste paper is used as the primary raw material). Examples of pulping methods include kraft, soda, sulfite, semi-chemical and mechanical.

If you have any questions regarding the applicability of this NESHAP, please contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

[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 WWW through the 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 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 section 307(b)(1) of the CAA, judicial review of this final action is available only by filing a petition for review in the Court by November 13, 2012. Under section 307(b)(2) of the CAA, the requirements established by these final rules may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce 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 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), CAA section 112(d) calls for the EPA to promulgate NESHAP for those sources. ''Major sources'' are those that emit or have the potential to emit 10 tpy or more of a single HAP or 25 tpy or more of any combination of HAP. For major sources, these technology-based standards must reflect the maximum degree of emissions reductions of HAP achievable (after considering cost, energy requirements and nonair quality health and environmental impacts) and are commonly referred to as 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. First, 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. Second, within 8 years after promulgation of the MACT standards, CAA section 112(f) calls for us to evaluate the risk to public health remaining after application of the 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. Under section 112(f)(2), the EPA may re-adopt the existing MACT standards if the EPA determines that those standards are sufficiently protective. *Natural Resources Defense Council (NRDC)* v. *EPA,* 529 F.3d 1077, 1083 (DC Cir. 2008).

On December 27, 2011, the EPA published a proposed rule in the **Federal Register** for the pulp and paper industry NESHAP, 40 CFR part 63, subpart S based on the RTR analyses that the EPA conducted under CAA sections 112(d)(6) and 112(f)(2) (76 FR 81328). Today's action provides the EPA's final determinations and regulatory amendments pursuant to the RTR provisions of CAA section 112.

In addition, several other aspects of the subpart S MACT rule were reviewed and considered for revision at proposal, and after review of the public comment received, we are taking the following actions:

- Finalizing the requirement for 5-year repeat emissions testing for selected process equipment.
- Revising the requirements in the NESHAP related to emissions during periods of SSM.
- Finalizing the requirement for electronic reporting of performance test data.
- Adding test methods for measuring methanol emissions.
- Finalizing changes to address technical and editorial corrections in the rule.

III. Summary of the Final Rule

A. What are the final rule amendments for the pulp and paper industry source category?

The NESHAP for the pulp and paper industry was promulgated on April 15, 1998 (63 FR 18504). The standards are codified at 40 CFR part 63, subpart S. The pulp and paper industry consists of facilities engaged in the production of pulp and/or paper/paperboard. This category includes, but is not limited to, integrated mills (where pulp and paper or paperboard are manufactured on-site), non-integrated mills (where paper/paperboard or pulp are manufactured, but not both), and secondary fiber mills (where waste paper is used as the primary raw material). The subpart S MACT standard applies to major sources of HAP emissions from the pulp production areas (e.g., pulping system vents, pulping process condensates) at chemical, mechanical, secondary fiber and non-wood pulp mills; bleaching operations; and papermaking systems. A separate NESHAP (40 CFR part 63, subpart MM) applicable to chemical recovery processes at kraft, soda, sulfite and stand-alone semi-chemical pulp mills was promulgated on January 12, 2001 (66 FR 3180). Today's rule takes final action only with respect to the RTR for subpart S. The source category covered by subpart S includes 171 facilities. As explained below, we are re-adopting the MACT standards pursuant to section 112(f)(2). We also conducted a section 112(d)(6) review and evaluated developments in practices, processes and control technologies applicable to all the emission sources subject to the pulp and paper MACT. After reviewing the comments provided at proposal, we have determined that our conclusion that there have been no developments in practices, processes and control technologies since the subpart S standard was originally promulgated was correct. Although we proposed revisions to the kraft pulping process condensate standards based on our conclusion at proposal that existing technologies were achieving greater than the 92 percent minimum level of control, we re-analyzed the performance data and impacts of revising the kraft condensate standards in response to public comments and have decided not to promulgate amendments to those standards because we found that the costs and impacts associated with the HAP reduction were not reasonable. Consequently, we are not revising the MACT standards for subpart S pursuant to our 112(d)(6) review as explained further below.

In addition, this section describes the other final rule amendments to the pulp and paper industry NESHAP. These revisions include the addition of repeat emissions testing for selected process equipment; changes to the requirements that apply during periods of SSM; the addition of electronic reporting requirements; and various minor changes to address technical and editorial corrections.

1. Repeat Emissions Testing

As part of an ongoing effort to improve compliance with the standard, we are adding 40 CFR 63.457(a)(2) to require repeat air emissions performance testing once every 5 years for facilities complying with the standards for kraft, soda and semi-chemical pulping vent gases (40 CFR 63.443(a)); sulfite processes (40 CFR 63.444); and bleaching systems (40 CFR 63.445). Repeat performance tests are already required by permitting authorities for some facilities.[2] Requiring periodic repeat performance tests will help to ensure that control systems are maintained properly over time and a more rigorous testing requirement will better assure compliance with the standard.[3]

In this action, repeat air emissions testing will be required for mills complying with the kraft pulping process condensate standards in 40 CFR 63.446 using a steam stripper since stripper off-gases are, by definition, part of the LVHC system. We are clarifying that repeat air emissions testing will not be required for: (1) Knotter or screen systems with HAP emission rates below the criteria specified in 40 CFR 63.443(a)(1)(ii); or (2) decker systems using fresh water or paper machine white water, or decker systems using process water with a total HAP concentration less than 400 ppmw as specified in 40 CFR 63.443(a)(1)(iv).

2. Startup, Shutdown and Malfunction

We are also finalizing changes to the subpart S NESHAP to eliminate the SSM exemption, as discussed further in section III.B below. The changes include:

(1) Revising 40 CFR 63.443(e), 63.446(g) and 63.459(b)(11)(ii) to eliminate reference to periods of SSM;

(2) Revising 40 CFR 63.453(q) to incorporate the general duty from 40 CFR 63.6(e)(1)(i) to minimize emissions;

(3) Adding 40 CFR 63.454(g), and 40 CFR 63.455(g) to require reporting and recordkeeping requirements associated with periods of malfunction;

(4) Adding 40 CFR 63.456 (formerly reserved) to include an affirmative defense to civil penalties for violations of emissions limits caused by malfunctions that meet the criteria for establishing the affirmative defense;

(5) Adding 40 CFR 63.457(o) to specify the conditions for performance tests; and

(6) Revising Table 1 to specify that 40 CFR 63.6(e)(1)(i) and (ii), 40 CFR 63.6(e)(3), 40 CFR 63.6(f)(1); 40 CFR 63.7(e)(1), 40 CFR 63.8(c)(1)(i) and (iii), and the last sentence of 40 CFR 63.8(d)(3); 40 CFR 63.10(b)(2)(i), (ii), (iv) and (v); 40 CFR 63.10(c)(10), (11) and (15); and, 40 CFR 63.10(d)(5) of the General Provisions do not apply.

3. Electronic Reporting

To increase the ease and efficiency of data submittal and improve data accessibility, we are requiring mills to submit electronic copies of performance test reports to the EPA's WebFIRE database, as discussed in section III.D below. The electronic reporting requirement is being added under 40 CFR 63.455(h).

4. Additional Test Methods for Measuring Methanol Emissions

To allow mills greater flexibility in demonstrating compliance with emission limits for total HAP measured as methanol, we are revising 40 CFR 63.457(b)(5)(i) to include four additional test methods for measuring methanol emissions from pulp and paper processes, as alternatives to EPA Method 308 of part 63, appendix A. The four additional test methods are:

(1) Method 18 of part 60, appendix A–6;

(2) Method 320 of part 63, appendix A;

(3) ASTM D6420–99, determined to be an acceptable alternative to EPA Method 18; and

(4) ASTM D6348–03, determined to be an acceptable alternative to EPA Method 320.

We are also revising 40 CFR 63.14(b)(28) and (b)(54) to IBR ASTM D6420–99 and ASTM D6348–03, respectively.

5. Other

We are also finalizing the following minor changes to the subpart S NESHAP and part 63 General Provisions to address technical and editorial corrections:

(1) Revising 40 CFR 63.457(b)(1) to specify part 60, appendix A–1 for Method 1 or 1A;

(2) Revising 40 CFR 63.457(b)(3) to specify part 60, appendix A–1 for Method 2, 2A, 2C or 2D;

(3) Revising 40 CFR 63.457(b)(5)(ii) to specify part 60, appendix A–8 for Method 26A;

(4) Revising 40 CFR 63.457(d) to specify part 60, appendix A–7 for Method 21;

(5) Revising 40 CFR 63.457(k)(1) to specify part 60, appendix A–2 for Method 3A or 3B, and include ASME PTC 19.10—part 10 as an alternative to Method 3B;

(6) Revising 40 CFR 63.457(c)(3)(ii) to replace NCASI Method DI/MEOH–94.02 with the more recent version of this method, NCASI Method DI/MEOH–94.03;

(7) Revising 40 CFR 63.14(f)(1) to incorporate by reference NCASI Method DI/MEOH–94.03;

(8) Redesignating 40 CFR 63.14(f)(3) and (f)(4) as 40 CFR 63.14(f)(4) and (f)(5) and adding 40 CFR 63.14(f)(3) to incorporate by reference NCASI Method DI/HAPS–99.01;

(9) Revising 40 CFR 63.14(i)(1) to incorporate by reference ANSI/ASME PTC 19.10–1981; and

(10) Revising Table 1 so it aligns more closely to the sections in subpart A which have been amended or reserved over time.

B. What are the requirements during periods of startup, shutdown and malfunction?

In 2008, 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), *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.

Consistent with *Sierra Club* v. *EPA,* we have eliminated the SSM exemption in this rule. We have also revised Table 1 (the General Provisions table) in several respects. For example, we have eliminated the General Provisions' requirement that the source develop a 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 for startup and shutdown, we reviewed the information available to us from the 2011 pulp and paper ICR pertaining to equipment and control and compliance demonstration methods during startup and shutdown. Some commenters

[2] Located in 11 states.

[3] For information on the cost associated with the repeat testing requirement, see the memorandum in the docket titled, *Costs, Environmental, and Energy Impacts for the Promulgated Subpart S Risk and Technology Review.*

suggested that we establish different standards for periods of startup and shutdown. However, the information available to us regarding startup and shutdown does not show that emissions are higher during startup or shutdown or indicate a need for alternate standards for these periods. Further, the commenters have not shown that sources cannot comply with the standards as proposed and have not provided information to support development of alternative standards that would apply during startup and shutdown periods.

Our findings relative to startup and shutdown for the universe of pulp and paper processes regulated under subpart S (which offers a variety of compliance options) are discussed in detail in the response-to-comments document and in a memorandum in the docket.[4] Based upon these findings, and consistent with our proposal, the EPA has not established different standards for startup and shutdown periods.

Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 63.2). 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 (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(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 violations. 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 a violation 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 violations of emission standards that are caused by malfunctions. See 40 CFR 63.441 (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 40 CFR 63.456. (See 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes a violation of the emission standard meets certain criteria. For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that the violation was "caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner * * *." The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.456 and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when a violation occurred * * *" and that "[a]ll possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health * * *." In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed

[4] See *Review of Pulp and Paper Information Collection Request (ICR) Responses Pertaining to Startup and Shutdown of Subpart S Equipment,* in the docket for the subpart S rulemaking.

in accordance with section 113 of the CAA (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 regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances beyond the control of the source. The EPA must establish emission standards that ''limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.'' 42 U.S.C. 7602(k) (defining ''emission limitation and emission standard''). See generally *Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (D.C. Cir. 2008). Thus, the EPA is required to ensure that section 112 emissions standards are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission standard is still enforceable through injunctive relief. While ''continuous'' standards, on the one hand, are required, there is also case law indicating that in many situations, it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), the 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 call into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for violations that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a CWA setting, the Ninth Circuit required this type of formalized approach when regulating ''upsets beyond the control of the permit holder.'' *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). See also, *Mont. Sulphur & Chem. Co.* v. *United States EPA,* 2012 U.S. App. LEXIS 1056 (Jan 19, 2012) (rejecting industry argument that reliance on the affirmative defense was not adequate). But see, *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission standards are ''continuous'' as required by 42 U.S.C. 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

C. What are the effective and compliance dates of the standards?

The revisions to subpart S being promulgated in this action are effective on September 11, 2012. The compliance date for the revisions we are finalizing today is September 11, 2012, with the exception of the following: (1) The first of the 5-year repeat tests must be conducted within 36 months of the effective date of the standards, by September 7, 2015, and thereafter within 60 months from the date of the previous performance test; and (2) the date to submit performance test data through ERT is within 60 days after the date of completing each performance test.

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

As stated in the proposed rule preamble, the EPA is taking a step to increase the ease and efficiency of data submittal and data accessibility. Specifically, the EPA is requiring owners and operators of pulp and paper facilities to submit electronic copies of required performance test reports.

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

The requirement to submit performance test data electronically to the EPA does not create any additional performance testing and will apply only to those performance tests conducted using test methods that are supported by the ERT. A listing of the pollutants and test methods supported by the ERT is available at the previously mentioned ERT Web site. Through this approach, industry is expected to save time in the performance test submittal process. Additionally this rulemaking benefits industry by cutting back on recordkeeping costs as the performance test reports that are submitted to the EPA using CEDRI are no longer required to be kept on-site.

As mentioned in the proposed rule preamble, state, local and tribal agencies will benefit from more streamlined and accurate review of electronic data that will be available on the EPA WebFIRE database. Additionally, performance test data will become available to the public through WebFIRE. Having such data publicly available enhances transparency and accountability. The major advantages of electronic reporting are more fully explained in the proposed rule preamble (76 FR 81348).

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 emissions 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)

As noted at proposal (76 FR 81344), the risk analysis performed for the pulp and paper source category indicated that the cancer risks to the individual most exposed are no higher than 10 in 1 million due to actual or MACT-allowable emissions. These risks are considerably less than 100 in 1 million, which is the presumptive upper limit of risk acceptability. The risk analysis also showed generally low cancer incidence (1 case every 100 years); no potential for adverse environmental effects or human health multipathway effects; no potential for chronic noncancer impacts; and, as explained in the proposal and further below, while a potential exists for some acute inhalation impacts, they are likely to be minimal because the potential impacts occur in uninhabited areas where terrain prevents ready access by the public. Also, we received comment on the risk assessment that is addressed in our comment response.[5]

The number of people exposed to cancer risks of 1 in 1 million or greater due to emissions from the source category was determined to be relatively low (76,000). The number of people exposed at the MIR cancer risk of 10 in 1 million or greater due to emissions

[5] See the memorandum in the docket titled, *National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (40 CFR Part 63, Subpart S) Residual Risk and Technology Review, Final Amendments Response to Public Comments on December 27, 2011 Proposal.*

from the source category was significantly lower (40). Considering all of this health information and the uncertainties discussed in the proposal preamble (76 FR 81338–40), the risks from the pulp and paper source category were deemed to be acceptable. 76 FR 81344.

Our analysis of facilitywide risks showed five mills with maximum chronic cancer risks between 10 and 30 in 1 million and four mills with maximum chronic noncancer TOSHI between 1 and 2. For the facility with the highest facilitywide risk (i.e., 30 in 1 million), emissions from the pulp and paper (subpart S) source category only contributed 27 percent to the chronic cancer risk and 23 percent to the chronic noncancer risk.

As directed by section 112(f)(2), we conducted an analysis to determine if the standard provides an ample margin of safety analysis to protect public health. Under the ample margin of safety analysis, we first considered the health impacts for the source category. Then we analyzed the potential for emissions reductions within the source category by evaluating available control technologies and their capabilities for reduction of the residual risk remaining after the implementation of MACT controls. Then we evaluated the potential costs and energy impacts of these additional controls. [6] Based on this analysis, we conclude that the current standard protects public health with an ample margin of safety. (76 FR 81344) We solicited comment on the proposal (76 FR 81349–51), asking for any additional data that may help to reduce the uncertainties inherent in the risk assessments and other analyses. We were specifically interested in receiving corrections to the mill-specific HAP emissions data used in the risk modeling. The mill-specific emissions data were available for download on the EPA's RTR web page at: *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html.* Commenters on the subpart S proposal were asked to determine whether any of the data were unrepresentative or inaccurate and to submit their comments on the data downloaded from the RTR web page.

A total of 81 mills submitted specific revisions to their mill-specific data. The EPA reviewed the data revisions to determine whether they would influence the outcome of the risk assessment results as proposed. Specifically, the mills submitted data revisions that remove pollutants, change emission release point type from fugitive to stack and change stack/fugitive emission parameters. Our review indicated that these changes would reduce emissions and/or impacts. Consequently, we have determined that the results of the revisions would most likely adjust the risk results for the subpart S source category downward (i.e., reduce risk) if we were to remodel the category. Therefore, we have decided not to remodel risk for purposes of promulgating the subpart S residual risk review because our conservative approach at proposal overstates existing risk and reinforces the conclusions from the risk modeling conducted at proposal. A memorandum for the docket was prepared that summarizes the data revisions received and supports the decision not to remodel risk.[7] A separate document presents the results of the EPA's risk analysis.[8] We conclude based on the Residual Risk Assessment cited here that the risks from the subpart S pulp and papermaking source category are acceptable and that the current standard protects the public health with an ample margin of safety. Consequently, we are re-adopting the MACT standards for subpart S pursuant to our 112(f)(2) review.

B. Changes to the Technology Review Performed Under CAA Section 112(d)(6)

As a result of our initial technology review, we proposed on December 27, 2011, to strengthen the kraft pulping process condensate standards in 40 CFR 63.446 by increasing the HAP removal requirement from 92 to 94 percent (or an equivalent pound/ODTP or ppmw limit). Several commenters opposed the proposed revisions to the kraft pulping process condensate standards, for reasons including calculation methodology issues, data misinterpretation, undetermined impacts on mills utilizing the clean condensate compliance alternative and additional steam and energy impacts for rule compliance. A detailed discussion of these comments can be found in the Response to Comment Document.[9]

In response to these comments, we have: (1) Re-analyzed the condensate collection information provided in the ICR; (2) evaluated the design criteria (and energy impacts) of the steam strippers and biotreatment units typically used by facilities to assure compliance with 40 CFR 63.446; (3) reviewed additional cost and control information that supplements the data collected in the ICR; and (4) considered the effects of the proposed standards on CCA mills.

In our re-analysis, we estimated the potential nationwide cost associated with increasing condensate treatment from 92 to 94 percent reduction would be $423 million (capital) and $85.1 million/yr. We estimated a HAP emissions reduction of 2,300 tpy, for a cost effectiveness of $37,000/ton of HAP. This estimate includes the costs associated with a repeat CCA demonstration and switching from CCA to HVLC pulping vent gas control at mills where the CCA approach would be adversely affected. Our revised cost estimates for a 94 percent reduction standard are significantly higher than the cost estimates that we developed at proposal for a 94 percent reduction standard because we determined that a greater number of mills would be affected after the potential impacts on CCA mills. Also, the cost-to-sales ratios for the three affected small businesses are also higher with one small business now estimated to have a ratio of 15 percent.[10] For this reason alone, we would decline to revise the standard under (d)(6) because we find increasing the standard from 92 percent to 94 percent not cost effective. In addition, after review of the comments, we recognize that we failed to fully consider the energy and secondary air emissions impacts associated with the 94 percent reduction limit for these mills, due to increased steam demand for new and upgraded stripper systems. Upon review of the information in the record, we believe these factors also weigh against revising the MACT standards. In the proposal, we estimated energy and secondary emissions impacts based on increased electricity requirements for biological treatment. We did not assume there were any additional impacts from new and upgraded steam strippers because they were expected to be more energy efficient, however, commenters indicated that additional steam would be required for these facilities. We have

[6] For a full discussion of this analysis, see the memorandum in the docket titled, *Ample Margin of Safety Analysis for Pulping and Papermaking Processes.*

[7] See the memorandum in the docket titled, *Recommendations Concerning Residual Risk Remodeling for the Pulp and Paper Industry.*

[8] See *Residual Risk Assessment for the Pulp and Paper Source Category,* in the docket for the subpart S rulemaking.

[9] See the memorandum in the docket titled, *National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (40 CFR Part 63, Subpart S) Residual Risk and Technology Review, Final Amendments Response to Public Comments on December 27, 2011, Proposal.*

[10] For further information on the costs and impacts associated with the 93 and 94 percent reduction options considered for promulgation of the kraft pulping process condensate standards, see the memorandum in the docket titled, *Costs, Environmental, and Energy Impacts for the Promulgated Subpart S Risk and Technology Review.*

considered these energy and secondary air emissions impacts for steam strippers for the final rule as a result of the public comments.[11]

Similarly, we also analyzed the potential nationwide costs and impacts of increasing the 92 percent reduction standard to 93 percent reduction. For a 93 percent reduction standard, estimated capital costs would be $396 million and estimated annualized costs would be $74.4 million/yr, with a HAP emission reduction of 989 tpy, or approximately $75,000/ton of HAP. Additionally, the cost-to-sales ratio is nearly 6 percent for one of the three small businesses.[12] For this reason alone, we would decline to revise the standard under (d)(6) because we find increasing the standard from 92 percent to 93 percent not cost effective. In addition, after review of the comments, we recognize that we failed to fully consider the energy and secondary air emissions impacts associated with the 93 percent reduction limit for these mills, due to increased steam demand for new and upgraded stripper systems. Upon review of the information in the record, we believe these factors also weigh against revising the MACT standards.

Based on this re-analysis, we do not consider the costs and impacts associated with the HAP reduction that would be achieved under either the 93 or 94 percent reduction options to be reasonable. Consequently we are not revising the MACT standards pursuant to section 112(d)(6).

C. Other Changes Since Proposal

1. Repeat Emissions Testing

In response to a comment, we have added language to clarify that the 5-year repeat testing is not required for: (1) Knotter or screen systems with HAP emission rates below the criteria specified in 40 CFR 63.443(a)(1)(ii); or (2) decker systems using fresh water or paper machine white water or decker systems using process water with a total HAP concentration less than 400 ppm by weight as specified in 40 CFR 63.443(a)(1)(iv).

2. Compliance Dates

Commenters requested clarification of the electronic reporting effective date since the proposed rule stated that performance test data must be submitted ''[a]s of January 1, 2012 and within 60 days of completing each performance test * * *''. The commenters noted that the January 1, 2012, date would require submission of performance testing before the final rule was in effect. In response to this comment, we have deleted reference to January 1, 2012, from the final rule. Electronic reports would be submitted within 60 days after completing each performance test.

3. Excess Emissions Allowances

Some commenters expressed concern regarding the EPA's request for comment in the preamble to the proposed rule (76 FR 81346) as to whether to remove or modify the excess emissions allowance provisions in 40 CFR 63.443(e), 63.446(g) and 63.459(b)(11)(ii). We are deferring final action on the excess emissions allowances until a later date in order to analyze more recent information on the allowances that we have obtained from industry. After we have completed our analysis of the data, we expect to publish a proposed rule describing the changes to the excess emissions allowance provisions that we believe are warranted and provide a further opportunity for public comment before taking final action with respect to the excess emissions allowance provisions.

4. Affirmative Defense

We have made certain changes to 40 CFR 63.456 for the final rule to clarify the circumstances under which a source may assert an affirmative defense. The changes to 40 CFR 63.456 clarify that a source may assert an affirmative defense to a claim for civil penalties for violations of standards that are caused by malfunctions. A source can avail itself of the affirmative defense when there has been a violation of the emission standards due to an event that meets the definition of malfunction under 40 CFR 63.2 and qualifies for assertion of an affirmative defense under § 63.456. In the proposal, we used terms such as ''exceedance'' or ''excess emissions'' in 40 CFR 63.456, which created unnecessary confusion as to when the affirmative defense could be used. In the final rule, we have eliminated those terms and used the word ''violation'' to make clear that the affirmative defense to civil penalties is available only where an event that causes a violation of the emissions standard meets the criteria for the assertion of an affirmative defense under § 63.456.

We have also eliminated the 2-day notification requirement that was included in 40 CFR 63.456(b) at proposal because we expect to receive sufficient notification of malfunction events that result in violations in other required compliance reports, such as the malfunction report required under 40 CFR 63.455(g). In addition, we have revised the 45-day affirmative defense reporting requirement that was included in 40 CFR 63.456(b) at proposal to require sources to include the report in the first compliance, deviation or excess emission report due after the initial occurrence of the violation, unless the compliance, deviation or excess emission report is due less than 45 days after the violation. In that case, the affirmative defense report may be included in the second compliance, deviation or excess emission report due after the initial occurrence of the violation. Because the affirmative defense report is now included in a subsequent compliance, deviation or excess emission report, there is no longer a need for the proposed 30-day extension for submitting a stand-alone affirmative defense report. Consequently, we are not including this provision in the final rule.

V. Summary of Cost, Environmental and Economic Impacts

A. What are the affected facilities?

There are currently 171 major source pulp and paper mills operating in the United States. The affected source for kraft, soda, sulfite or semi-chemical pulping processes is the total of all HAP emission points in the pulping and bleaching systems. The affected source for mechanical, secondary or non-wood pulping processes is the total of all HAP emission points in the bleaching system. We estimate that 114 of the 171 major source mills operate subpart S processes that are affected by this final rule.

B. What are the air quality impacts?

These final amendments will require an estimated 114 mills to conduct repeat testing for pulping and bleaching operations and all major sources with equipment subject to the subpart S standards to operate without the SSM exemption. We were unable to quantify the specific emissions reductions associated with repeat emissions testing or eliminating the SSM exemption. However, repeat testing will tend to reduce emissions by providing incentive for facilities to maintain their control systems and make periodic adjustments to ensure peak performance. Eliminating the SSM exemption will reduce emissions by requiring facilities to meet the applicable standard during SSM periods.

Section IV.B of this preamble presents estimates of the air quality impacts associated with the kraft pulping process condensate regulatory options that were not selected for inclusion in this final rule.

[11] *Id.*

[12] *Id.*

C. What are the cost impacts?

Pulp and paper mills will incur costs to conduct repeat testing and record malfunctions in support of the new affirmative defense in the rule. Costs associated with elimination of the startup and shutdown exemption were estimated as part of the reporting and recordkeeping costs and include time for re-evaluating previously developed SSM record systems. Nationwide capital costs are estimated to be $5.9 million. The total nationwide annualized costs associated with these new requirements are estimated to be $2.1 million per year.

Section IV.B of this preamble presents cost estimates associated with the kraft pulping process condensate regulatory options that were not selected for inclusion in this final rule.

D. What are the economic impacts?

We performed an EIA of the final rule for pulp and paper consumers and producers nationally. The EIA, which documents the data sources and methods used and provides detailed results, can be found in the docket for the final rule. This section provides an overview of key results.

The final rule induces minimal changes in the average national price of paper and paperboard products. Paper and paperboard product prices increase less than 0.01 percent on average, while production levels decrease less that 0.01 percent on average, as a result of the final rule. Consumers are estimated to experience a reduction in economic welfare of about $1.1 million as the result of slightly higher prices and slightly reduced consumption. Although producers' welfare losses are mitigated to some degree by slightly higher prices, market conditions limit their ability to pass on all of the compliance costs. As a result, they also are estimated to experience a loss in economic welfare of about $1.0 million as a result of the final rule.

E. What are the benefits?

Because this rulemaking is not likely to have an annual effect on the economy of $100 million or more, we have not conducted a RIA or a benefits analysis. Since we were unable to quantify the emissions reductions associated with the new requirements in the final rule (repeat testing and elimination of the SSM exemption), we were also unable to quantify the monetary benefits associated with these new requirements.

VI. 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 and policy issues. Accordingly, the EPA submitted this action to OMB for review under Executive Order 12866 and 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to OMB under the PRA, 44 U.S.C. 3501, *et seq.* The ICR document prepared by the EPA has been assigned EPA ICR number 2452.02. 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.

This final rule includes new paperwork requirements for repeat testing for selected process equipment, as described in 40 CFR 63.457(a)(2). More specifically, we are requiring stack testing every 5 years for total HAP for chemical pulping operations and bleaching operations at pulp and paper mills. This final rule also includes new paperwork requirements for recordkeeping of malfunctions, as described in 40 CFR 63.454(g) (conducted in support of the affirmative defense provisions, as described in 40 CFR 63.456).

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

The EPA is adding 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 for any individual incident, including the root cause analysis, totals $3,258, and is based on the time and effort required of a source to review relevant data, interview plant employees and document the events surrounding a malfunction that has caused a violation of an emissions limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense.

Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a

small number would be expected to result from a malfunction (based on the definition above), and only a subset of violations caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we expect the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small. For this reason, we estimate no more than two such occurrences per year for all sources subject to subpart S 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 estimated recordkeeping and reporting burden associated with subpart S after the effective date of the final rule is estimated to be 52,300 labor hours at a cost of $4.94 million per year and total non-labor capital and O&M costs of $841,000 per year. This estimate includes reporting costs, such as reading and understanding the rule requirements, conducting required activities (e.g., stack testing, inspections), and preparing notifications and compliance reports and recordkeeping costs associated with malfunctions, monitoring and inspections. The total burden for the federal government is estimated to be 6,870 hours per year at a total labor cost of $310,000 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 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 numbers 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 SISNOSE. 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 SBA'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. For this source category, which has the general NAICS subsector code 322 (i.e., Paper Manufacturing), the SBA small business size standard is 500 to 750 employees (depending on the specific NAICS code) according to the SBA small business standards definitions.

The EPA analyzed impacts on small businesses by comparing estimated annualized engineering compliance costs at the company-level to company revenue. The analysis found that the ratio of compliance cost to company revenue falls below 1 percent for the three small companies that are likely to be affected by the finalized rule. After considering the economic impacts of this final rule on small entities, I certify that this action will not have a SISNOSE. See the EIA in the docket for this rule for more details on this analysis.

Although this final rule will not have a SISNOSE, the EPA nonetheless has tried to reduce the impact of this rule on small entities. The proposed amendment tightening the kraft pulping process condensate standards was not finalized after the EPA re-evaluated the amendment and its costs and impacts in response to public comments (see section IV.B of this preamble for further information). The repeat testing requirement was 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 final standards. Also, the final malfunction recordkeeping requirement was designed to provide all pulp and paper companies, including small entities, with a means of supporting an affirmative defense in the event of a violation occurring during a malfunction.

D. Unfunded Mandates Reform Act

This action does not contain a federal mandate under the provisions of Title II of the UMRA, 2 U.S.C. 1531–1538 for state, local or tribal governments or the private sector. This final rule is not expected to impact state, local or tribal governments. The nationwide annual cost of this final rule for affected sources is $2.1 million. Thus, this rule is not subject to the requirements of sections 202 or 205 of the UMRA.

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

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. None of the facilities subject to this action are owned or operated by state governments and nothing in this final rule will supersede state regulations. The burden to the respondents and the states is less than $2.1 million for the entire source category. Thus, Executive Order 13132 does not apply to this final rule.

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

This 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 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. However, the EPA did outreach and consultation on this rule. The EPA presented this information to the tribes prior to proposal of this rule via a call with the National Tribal Air Association. In addition, the EPA presented the information on the sources and the industry at the National Tribal Forum in Spokane, Washington. The EPA also offered consultation by letters sent to all tribal leaders. We held that consultation with the Nez Perce, Forest County Potowatomi and Leech Lake Band of Ojibewa on October 6, 2011. Additionally, a public outreach webinar was conducted during the comment period on January 31, 2012, to review the proposed rule. The webinar was coordinated with the tribal governments and the general public.

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

This final rule 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 agency does not believe the environmental health risks 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 assessment results—included in the preamble (76 FR 81344) and docket (EPA–HQ–OAR–2007–0544) for the proposed rule—demonstrate that the existing regulation is 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 under 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.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA, Public Law No. 104–113, 12(d) (15 U.S.C. 272 note), directs the EPA to use VCS in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures and business practices) that are developed or adopted by VCS bodies. The 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 has decided to use three VCS in this final rule.

One VCS, ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' is cited in this final rule for its manual method of measuring the content of the exhaust gas as an acceptable alternative to EPA Method 3B of appendix A–2. This standard is available at *http://www.asme.org* or by mail at the ASME, Post Office Box 2900, Fairfield, NJ 07007–2900; or at Global Engineering Documents, Sales Department, 15 Inverness Way East, Englewood, CO 80112.

A second VCS, ASTM D6420–99 (2010), ''Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry'' is cited as an acceptable alternative to EPA Method 18. A third VCS, ASTM D6348–03 (2010), ''Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy,'' was determined to be an acceptable alternative to EPA Method 320. EPA Methods 18 and 320 are added as alternatives to EPA Method 308 in this final rule for measurement of methanol emissions. The two VCS alternatives are available for purchase from ASTM International, 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106.

While the EPA has identified another 14 VCS as being potentially applicable to this final rule, we have decided not to use these VCS in this rulemaking. The use of these VCS would be impractical because they do not meet the objectives of the standards cited in this rule. See the docket for this rule for the reasons for these determinations.

Under 40 CFR 63.7(e)(2)(ii) and (f) and 63.8(f) of the NESHAP General Provisions, a source may apply to the EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications or procedures in the final rule and any amendments.

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

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on 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 this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income or indigenous populations because it does not affect the level of protection provided to human health or the environment.

These final standards will not relax the control measures on sources regulated by the rule and, therefore, will not cause emissions increases from these sources. In fact, as noted in section III.A of this preamble, the repeat testing provisions included in this final rule will tend to reduce emissions by providing incentive for facilities to maintain their control systems and make periodic adjustments to ensure peak performance. Also, eliminating the SSM exemption will reduce emissions by requiring facilities to meet the applicable standard during SSM periods.

Additionally, the agency has reviewed this rule to determine if there is an overrepresentation of minority, low income or indigenous populations near the sources such that they may face disproportionate exposure from pollutants that could potentially be mitigated by this rulemaking. 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.

The demographic data show that while most demographic categories are below, or within, 2 percentage points of national averages, the African-American population exceeds the national average by 3 percentage points (15 percent versus 12 percent), or +25 percent. The facility-level demographic analysis results are presented in the November 2011 memorandum titled, *Review of Environmental Justice Impacts: Pulp and Paper,* a copy of which is available in the docket for this action (EPA–HQ–OAR–2007–0544).

The analysis of demographic data used proximity-to-a-source as a surrogate for exposure to identify those populations considered to be living near affected sources, such that they have measurable exposures to current HAP 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 with ages 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 3 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 km) is consistent with other demographic analyses focused on areas around potential sources.[13 14 15 16] In addition, air quality modeling experience has shown that the area within 3 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). While 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 or 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 that may result from this rule.

The EPA did outreach and consultation on this rule on the subject of federal actions to address EJ issues. The EPA requested input on EJ issues prior to proposal of this rule in regional conference calls and at the EPA's national EJ conference in 2011. Additionally, a public outreach webinar was conducted during the comment period on January 31, 2012, to review the proposed rule. As noted above, the webinar was coordinated with the tribal governments and the general public.

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

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

[15] 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.

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

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that, before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). The final rule will be effective on September 11, 2012.

National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Incorporation by reference, Reporting and recordkeeping requirements.

Dated: July 31, 2012.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency is amending 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 A—[Amended]

■ 2. Section 63.14 is amended by:
■ a. Revising paragraph (b)(28);
■ b. Revising paragraph (b)(54);
■ c. Revising paragraph (f)(1);
■ d. Redesignating paragraphs (f)(3) and (4) as paragraphs (f)(4) and (5);
■ e. Adding new paragraph (f)(3); and
■ f. Revising paragraph (i)(1).

The revisions read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) * * *

(28) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, approved 2004, IBR approved for §§ 60.485, 60.485a, 63.457, 63.772, 63.2351, 63.2354, and table 8 to subpart HHHHHHH of this part.

* * * * *

(54) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved 2003, IBR approved for §§ 63.457, 63.1349, table 4 to subpart DDDD of this part, and table 8 to subpart HHHHHHH of this part.

* * * * *

(f) * * *

(1) NCASI Method DI/MEOH–94.03, Methanol in Process Liquids and Wastewaters by GC/FID, Issued May 2000, IBR approved for §§ 63.457 and 63.459 of subpart S of this part.

* * * * *

(3) NCASI Method DI/HAPS–99.01, Selected HAPs In Condensates by GC/FID, Issued February 2000, IBR approved for § 63.459(b) of subpart S 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, 63.457(k), 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.

* * * * *

Subpart S—[Amended]

* * * * *

■ 3. Section 63.441 is amended by adding a definition for "affirmative defense," in alphabetical order, to read as follows:

§ 63.441 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.

* * * * *

■ 4. Section 63.443 is amended by revising paragraph (e) introductory text to read as follows:

§ 63.443 Standards for the pulping system at kraft, soda, and semi-chemical processes.

* * * * *

(e) Periods of excess emissions reported under § 63.455 shall not be a violation of § 63.443(c) and (d) provided that the time of excess emissions divided by the total process operating time in a semi-annual reporting period does not exceed the following levels:

* * * * *

■ 5. Section 63.446 is amended by revising paragraph (g) to read as follows:

§ 63.446 Standards for kraft pulping process condensates.

* * * * *

(g) For each control device (e.g., steam stripper system or other equipment serving the same function) used to treat pulping process condensates to comply with the requirements specified in paragraphs (e)(3) through (5) of this section, periods of excess emissions reported under § 63.455 shall not be a violation of paragraphs (d), (e)(3) through (5), and (f) of this section provided that the time of excess emissions divided by the total process operating time in a semi-annual reporting period does not exceed 10 percent. The 10 percent excess emissions allowance does not apply to treatment of pulping process condensates according to paragraph (e)(2) of this section (e.g., the biological wastewater treatment system used to treat multiple (primarily non-condensate) wastewater streams to comply with the Clean Water Act).

* * * * *

■ 6. Section 63.453 is amended by adding paragraph (q) to read as follows:

§ 63.453 Monitoring requirements.

* * * * *

(q) 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.

■ 7. Section 63.454 is amended by revising paragraph (a) and adding paragraph (g) to read as follows:

§ 63.454 Recordkeeping requirements.

(a) The owner or operator of each affected source subject to the requirements of this subpart shall comply with the recordkeeping requirements of § 63.10, as shown in Table 1 of this subpart, and the requirements specified in paragraphs (b) through (g) of this section for the monitoring parameters specified in § 63.453.

* * * * *

(g) *Recordkeeping of malfunctions.* The owner or operator must maintain the following records of malfunctions:

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

(2) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.453(q), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

■ 8. Section 63.455 is amended by adding paragraphs (g) and (h) to read as follows:

§ 63.455 Reporting requirements.

* * * * *

(g) *Malfunction reporting requirements.* If a malfunction occurred during the reporting period, the 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 § 63.453(q), including actions taken to correct a malfunction.

(h) The owner or operator must submit performance test reports as specified in paragraphs (h)(1) through (4) of this section.

(1) The owner or operator of an affected source shall report the results of the performance test before the close of business on the 60th day following the completion of the performance test, unless approved otherwise in writing by the Administrator. A performance test is ''completed'' when field sample collection is terminated. Unless otherwise approved by the Administrator in writing, results of a performance test shall include the analysis of samples, determination of emissions and raw data. A complete test report must include the purpose of the test; a brief process description; a complete unit description, including a description of feed streams and control devices; sampling site description; pollutants measured; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions, including operating parameters for which limits are being set, 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; chain-of-custody documentation; explanation of laboratory data qualifiers; example calculations of all applicable stack gas parameters, emission rates, percent reduction rates, and analytical results, as applicable; and any other information required by the test method and the Administrator.

(2) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart, the owner or operator must submit the results of the performance tests, including any associated fuel analyses, required by this subpart to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk, flash drive or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, the owner or operator must also submit these reports, including the CBI, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using

test methods that are not listed on the ERT Web site, the owner or operator must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

(3) Within 60 days after the date of completing each CEMS performance evaluation test as defined in § 63.2, the owner or operator must submit relative accuracy test audit (RATA) data to the EPA's CDX by using CEDRI in accordance with paragraph (2) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator must submit the results of the performance evaluation to the Administrator at the appropriate address listed in § 63.13.

(4) All reports required by this subpart not subject to the requirements in paragraphs (h)(2) and (3) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraphs (h)(2) and (3) of this section in paper format.

■ 9. Section 63.456 is added to read as follows:

§ 63.456 Affirmative defense for violation of emission standards during malfunction.

In response to an action to enforce the standards set forth in §§ 63.443(c) and (d), 63.444(b) and (c), 63.445(b) and (c), 63.446(c), (d), and (e), 63.447(b) or § 63.450(d), the owner or operator 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 the owner or operator fails to meet the burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

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

(1) The violation:

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

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

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

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

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

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

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

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

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

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

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

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

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

■ 10. Section 63.457 is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraph (b)(1) introductory text;
■ c. Revising paragraph (b)(3);
■ d. Revising paragraph (b)(4);
■ e. Revising paragraph (b)(5)(i);
■ f. Revising paragraph (b)(5)(ii) introductory text;
■ g. Revising paragraph (c)(3)(ii);
■ h. Revising paragraph (d)(1);
■ i. Revising paragraph (k)(1); and
■ j. Adding paragraph (o).

The revisions read as follows:

§ 63.457 Test methods and procedures.

(a) *Performance tests.* Initial and repeat performance tests are required for the emissions sources specified in paragraphs (a)(1) and (2) of this section, except for emission sources controlled by a combustion device that is designed and operated as specified in § 63.443(d)(3) or (4).

(1) Conduct an initial performance test for all emission sources subject to the limitations in §§ 63.443, 63.444, 63.445, 63.446, and 63.447.

(2) Conduct repeat performance tests at five-year intervals for all emission sources subject to the limitations in §§ 63.443, 63.444, and 63.445. The first of the 5-year repeat tests must be conducted by September 7, 2015, and thereafter within 60 months from the date of the previous performance test. Five-year repeat testing is not required for the following:

(i) Knotter or screen systems with HAP emission rates below the criteria specified in § 63.443(a)(1)(ii).

(ii) Decker systems using fresh water or paper machine white water, or decker systems using process water with a total HAP concentration less than 400 parts per million by weight as specified in § 63.443(a)(1)(iv).

(b) * * *

(1) Method 1 or 1A of part 60, appendix A–1, as appropriate, shall be used for selection of the sampling site as follows:

* * * * *

(3) The vent gas volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D of part 60, appendix A–1, as appropriate.

(4) The moisture content of the vent gas shall be measured using Method 4 of part 60, appendix A–3.

(5) * * *

(i) Method 308 in Appendix A of this part; Method 320 in Appendix A of this part; Method 18 in appendix A–6 of part 60; ASTM D6420–99 (Reapproved 2004) (incorporated by reference in § 63.14(b)(28) of subpart A of this part); or ASTM D6348–03 (incorporated by reference in § 63.14(b)(54) of subpart A of this part) shall be used to determine the methanol concentration. If ASTM D6348–03 is used, the conditions specified in paragraphs (b)(5)(i)(A) though (b)(5)(i)(B) must be met.

(A) The test plan preparation and implementation in the Annexes to ASTM D6348–03, sections A1 through A8 are required.

(B) In ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5 of ASTM D6348–03). In order for the test data to be acceptable for a compound, %R must be between 70 and 130 percent. If the %R value does not meet this criterion for a target compound, the test data is not acceptable for that compound and the test must be repeated for that analyte following adjustment of the sampling or analytical procedure before the 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 using the following equation: Reported Result = Measured Concentration in the Stack × 100)/%R.

(ii) Except for the modifications specified in paragraphs (b)(5)(ii)(A) through (b)(5)(ii)(K) of this section, Method 26A of part 60, appendix A–8 shall be used to determine chlorine concentration in the vent stream.

* * * * *

(c) * * *

(3) * * *

(ii) For determining methanol concentrations, NCASI Method DI/MEOH–94.03. This test method is incorporated by reference in § 63.14(f)(1) of subpart A of this part.

* * * * *

(d) * * *

(1) Method 21, of part 60, appendix A–7; and

* * * * *

(k) * * *

(1) The emission rate correction factor and excess air integrated sampling and analysis procedures of Methods 3A or 3B of part 60, appendix A–2 shall be used to determine the oxygen concentration. The samples shall be taken at the same time that the HAP samples are taken. As an alternative to Method 3B, ASME PTC 19.10–1981 [Part 10] may be used (incorporated by reference, see § 63.14(i)(1)).

* * * * *

(o) 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.

■ 11. Section 63.459 is amended by:

■ a. Revising paragraph (b)(5)(iv)(A) introductory text;

■ b. Revising paragraph (b)(5)(iv)(A)(*2*);

■ c. Revising paragraph (b)(8)(ii);

■ d. Revising paragraph (b)(8)(iii); and

■ e. Revising paragraph (b)(11)(ii).

The revisions read as follows:

§ 63.459 Alternative standards.

* * * * *

(b) * * *

(5) * * *

(iv) * * *

(A) The owner or operator shall measure the methanol concentration of the outfall of any basin, using NCASI Method DI/MEOH 94.03 (incorporated by reference, see § 63.14), when the VA/A ratio of that basin exceeds the following:

* * * * *

(*2*) The highest VA/A ratio at which the outfall of any basin has previously measured non-detect for methanol, using NCASI Method DI/MEOH 94.03 (incorporated by reference, see § 63.14).

* * * * *

(8) * * *

(ii) The owner or operator shall use NCASI Method DI/HAPS–99.01 (incorporated by reference, see § 63.14) to collect a grab sample and determine the HAP concentration of the Raw Mill Effluent, Pulping Process Condensates, and Anaerobic Basin Discharge for the quarterly performance test conducted during the first quarter each year.

(iii) For each of the remaining three quarters, the owner or operator may use NCASI Method DI/MEOH 94.03 (incorporated by reference, see § 63.14) as a surrogate to collect and determine the HAP concentration of the Raw Mill Effluent, Pulping Process Condensates, and Anaerobic Basin Discharge.

* * * * *

(11) * * *

(ii) Periods of excess emissions shall not constitute a violation provided the time of excess emissions divided by the total process operating time in a semi-annual reporting period does not exceed one percent. All periods of excess emission shall be reported, and shall include:

* * * * *

■ 12. Table 1 to subpart S is revised to read as follows:

TABLE 1 TO SUBPART S OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART S [a]

Reference	Applies to subpart S	Comment
63.1(a)(1)–(3)	Yes	
63.1(a)(4)	Yes	Subpart S (this table) specifies applicability of each paragraph in subpart A to subpart S.
63.1(a)(5)	No	Section reserved.
63.1(a)(6)	Yes	
63.1(a)(7)–(9)	No	Sections reserved.
63.1(a)(10)	No	Subpart S and other cross-referenced subparts specify calendar or operating day.
63.1(a)(11)–(12)	Yes	
63.1(b)(1)	No	Subpart S specifies its own applicability.
63.1(b)(2)	No	Section reserved.
63.1(b)(3)	Yes	
63.1(c)(1)–(2)	Yes	
63.1(c)(3)–(4)	No	Sections reserved.
63.1(c)(5)	Yes	
63.1(d)	No	Section reserved.
63.1(e)	Yes	
63.2	Yes	

TABLE 1 TO SUBPART S OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART S [a]—Continued

Reference	Applies to subpart S	Comment
63.3	Yes	
63.4(a)(1)–(2)	Yes	
63.4(a)(3)–(5)	No	Sections reserved.
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)	Yes	
63.5(b)(1)	Yes	
63.5(b)(2)	No	Section reserved.
63.5(b)(3)–(4)	Yes	
63.5(b)(5)	No	Section reserved.
63.5(b)(6)	Yes	
63.5(c)	No	Section reserved.
63.5(d)	Yes	
63.5(e)	Yes	
63.5(f)	Yes	
63.6(a)	Yes	
63.6(b)(1)–(5)	No	Subpart S specifies compliance dates for sources subject to subpart S.
63.6(b)(6)	No	Section reserved.
63.6(b)(7)	No	Subpart S specifies compliance dates for sources subject to subpart S.
63.6(c)(1)–(2)	No	Subpart S specifies compliance dates for sources subject to subpart S.
63.6(c)(3)–(4)	No	Sections reserved.
63.6(c)(5)	No	Subpart S specifies compliance dates for sources subject to subpart S.
63.6(d)	No	Section reserved.
63.6(e)(1)(i)	No	See § 63.453(q) 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)–(3)	Yes	
63.6(g)	Yes	
63.6(h)(1)–(2)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.6(h)(3)	No	Section reserved.
63.6(h)(4)–(9)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.6(i)(1)–(14)	Yes	
63.6(i)(15)	No	Section reserved.
63.6(i)(16)	Yes	
63.6(j)	Yes	
63.7(a)	Yes	
63.7(b)	Yes	
63.7(c)	Yes	
63.7(d)	Yes	
63.7(e)(1)	No	Replaced with § 63.457(o), which specifies performance testing conditions under subpart S.
63.7(e)(2)–(4)	Yes	
63.7(f)	Yes	
63.7(g)(1)	Yes	
63.7(g)(2)	No	Section reserved.
63.7(g)(3)	Yes	
63.7(h)	Yes	
63.8(a)(1)–(2)	Yes	
63.8(a)(3)	No	Section reserved.
63.8(a)(4)	Yes	
63.8(b)(1)	Yes	
63.8(b)(2)	No	Subpart S specifies locations to conduct monitoring.
63.8(b)(3)	Yes	
63.8(c)(1)–(c)(1)(i)	No	See § 63.453(q) for general duty requirement (which includes monitoring equipment).
63.8(c)(1)(ii)	Yes	
63.8(c)(1)(iii)	No	
63.8(c)(2)–(3)	Yes	
63.8(c)(4)	No	Subpart S allows site specific determination of monitoring frequency in § 63.453(n)(4).
63.8(c)(5)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.8(c)(6)–(8)	Yes	
63.8(d)(1)–(2)	Yes	
63.8(d)(3)	Yes, except for last sentence, which refers to an SSM plan.	SSM plans are not required

TABLE 1 TO SUBPART S OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART S [a]—Continued

Reference	Applies to subpart S	Comment
63.8(e)	Yes	
63.8(f)(1)–(5)	Yes	
63.8(f)(6)	No	Subpart S does not specify relative accuracy test for CEMs.
63.8(g)	Yes	
63.9(a)	Yes	
63.9(b)(1)–(2)	Yes	Initial notifications must be submitted within one year after the source becomes subject to the relevant standard.
63.9(b)(3)	No	Section reserved.
63.9(b)(4)–(5)	Yes	
63.9(c)	Yes	
63.9(d)	No	Special compliance requirements are only applicable to kraft mills.
63.9(e)	Yes	
63.9(f)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.9(g)(1)	Yes	
63.9(g)(2)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.9(g)(3)	No	Subpart S does not specify relative accuracy tests, therefore no notification is required for an alternative.
63.9(h)(1)–(3)	Yes	
63.9(h)(4)	No	Section reserved.
63.9(h)(5)–(6)	Yes	
63.9(i)	Yes	
63.9(j)	Yes	
63.10(a)	Yes	
63.10(b)(1)	Yes	
63.10(b)(2)(i)	No	
63.10(b)(2)(ii)	No	See § 63.454(g) for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
63.10(b)(2)(iii)	Yes	
63.10(b)(2)(iv)–(v)	No	
63.10(b)(2)(vi)–(xiv)	Yes	
63.10(b)(3)	Yes	
63.10(c)(1)	Yes	
63.10(c)(2)–(4)	No	Sections reserved.
63.10(c)(5)–(8)	Yes	
63.10(c)(9)	No	Section reserved.
63.10(c)(10)–(11)	No	See § 63.454(g) for malfunction recordkeeping requirements.
63.10(c)(12)–(14)	Yes	
63.10(c)(15)	No	
63.10(d)(1)–(2)	Yes	
63.10(d)(3)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.10(d)(4)	Yes	
63.10(d)(5)	No	See § 63.455(g) for malfunction reporting requirements.
63.10(e)(1)	Yes	
63.10(e)(2)(i)	Yes	
63.10(e)(2)(ii)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.10(e)(3)	Yes	
63.10(e)(4)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.10(f)	Yes	
63.11–63.15	Yes	

[a] Wherever subpart A specifies "postmark" dates, submittals may be sent by methods other than the U.S. Mail (e.g., by fax or courier). Submittals shall be sent by the specified dates, but a postmark is not required.

[FR Doc. 2012–20501 Filed 9–10–12; 8:45 am]

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FEDERAL COMMUNICATIONS COMMISSION

47 CFR Parts 2 and 95

[ET Docket No. 08–59; FCC 12–54]

Medical Area Body Network

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: This document expands the Commission's Medical Device Radiocommunications Service (MedRadio) rules to permit the development of new Medical Body Area Network (MBAN) devices in the 2360–2400 MHz band. The MBAN technology will provide a flexible platform for the wireless networking of multiple body transmitters used for the purpose of measuring and recording physiological parameters and other patient information or for performing diagnostic or therapeutic functions, primarily in health care facilities. This platform will enhance patient safety, care and comfort by reducing the need to physically connect sensors to essential monitoring equipment by cables and wires. This decision is the latest in a series of actions to expand the spectrum available for wireless medical use. The Commission finds that the risk of increased interference is minimal and is greatly outweighed by the benefits of the MBAN rules.

DATES: Effective October 11, 2012, except for §§ 95.1215(c), 95.1217(a)(3), 95.1223, and 95.1225, which contain information collection requirements that

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Part II

Environmental Protection Agency

40 CFR Part 63

National Emission Standards for Hazardous Air Pollutant Emissions: Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks; and Steel Pickling—HCl Process Facilities and Hydrochloric Acid Regeneration Plants; Final Rules

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2010–0600; FRL–9709–9]

RIN 2060–AQ60

National Emission Standards for Hazardous Air Pollutant Emissions: Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks; and Steel Pickling—HCl Process Facilities and Hydrochloric Acid Regeneration Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes the residual risk and technology review conducted for the following source categories regulated under two national emission standards for hazardous air pollutants (NESHAP): hard and decorative chromium electroplating and chromium anodizing tanks, and steel pickling—HCl process facilities and hydrochloric acid regeneration plants. On October 21, 2010, EPA proposed amendments to these NESHAP under section 112(d)(6) and (f)(2) of the Clean Air Act. On February 8, 2012, EPA published a supplemental proposal with new analyses and results. For hard and decorative chromium electroplating and chromium anodizing tanks these final amendments addressing Clean Air Act (CAA) sections 112(d)(6) and (f)(2) include revisions to the emissions limits for total chromium; addition of housekeeping requirements to minimize fugitive emissions; and a requirement to phase-out the use of perfluorooctane sulfonic acid (PFOS) based fume suppressants. These requirements will provide greater protection for public health and the environment by reducing emissions of hexavalent chromium (a known human carcinogen). In addition, as part of the October 2010 proposal, we proposed certain actions pursuant to CAA section 112(d)(2) and (3) for hard and decorative chromium electroplating and chromium anodizing tanks. For these sources, we are modifying and adding testing and monitoring, recordkeeping, and reporting requirements; and revisions to the regulatory provisions related to emissions during periods of malfunction. For steel pickling hydrochloric acid regeneration plants, we are finalizing our proposal to remove the alternative compliance method because we believe it is inconsistent with the requirements of CAA section 112(d)(2) and (3). This amendment will achieve reductions in chlorine emissions. Additionally, we are adding provisions to the Steel Pickling Facilities NESHAP requiring that the emission limits of the rule apply at all times, including during periods of startup, shutdown and malfunction.

DATES: This final action is effective on September 19, 2012.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2010–0600. 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 rule, contact Mr. Phil Mulrine, Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone (919) 541–5289; fax number: (919) 541–3207; and email address: *mulrine.phil@epa.gov.* For specific information regarding the risk modeling methodology, contact Mr. Mark Morris, Health and Environmental Impacts Division (C539–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–5416; fax number: (919) 541–0840; and email address: *morris.mark@epa.gov.*

SUPPLEMENTARY INFORMATION: For information about the applicability of these 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]
Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks; and Steel Pickling—HCl Process Facilities and Hydrochloric Acid Regeneration Plants.	Sara Ayres, (202) 564–5391, *ayres.sara@epa.gov.*	Phil Mulrine, (919) 541–5289, *mulrine.phil@epa.gov.*

[a] EPA's Office of Enforcement and Compliance Assurance.
[b] EPA's Office of Air Quality Planning and Standards.

Organization of this Document. The information in this preamble is organized as follows:

I. General Information
A. Executive Summary
B. Does this action apply to me?
C. Where can I get a copy of this document and other related information?
D. Judicial Review
II. Background Information
A. Overview of the Chromium Electroplating and Chromium Anodizing Source Categories
B. Summary of the Proposed Amendments to the Chromium Electroplating and Chromium Anodizing Source Categories
C. Overview of the Steel Pickling Source Category
D. Summary of the Proposed Amendments to the Steel Pickling Source Category
III. Summary of the Final Rule
A. What are the final rule amendments for the Chromium Electroplating and Chromium Anodizing source categories?
B. What are the effective and compliance dates for the Chromium Electroplating and Chromium Anodizing source category amendments?
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D. What are the effective and compliance dates for the Steel Pickling source category amendments?
IV. Summary of Significant Comments and Responses
A. Comments and Responses Associated With the Chromium Electroplating and Chromium Anodizing Source Categories
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V. Summary of Cost, Environmental and Economic Impacts
A. What are the affected sources?
B. What are the emission reductions?
C. What are the cost impacts?
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E. What are the benefits?
VI. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

This action presents the results and final decisions based on EPA's review of two national regulations for hazardous air pollutants. Specifically, pursuant to the Clean Air Act (CAA), EPA has completed risk and technology reviews (RTRs) for four source categories covered by two separate regulations.

Section 112(d)(6) of the CAA requires EPA to review these regulations (i.e., national emissions standards) and revise them as necessary (taking into account developments in practices, processes, and control technologies) no less frequently than every 8 years. Section 112(f)(2) of the CAA requires EPA to assess the remaining risks due to emissions of hazardous air pollutants (HAP) from these source categories and determine whether the emissions standards provide an ample margin of safety to protect public health within 8 years of promulgation of the original standards. The two regulations addressed in this action are the following: National Emissions Standards for Chromium Emissions from Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks; and National Emissions Standards for Hazardous Air Pollutants for Steel Pickling—HCl Process Facilities and Hydrochloric Acid Regeneration Plants.

In addition to the reviews described above, the EPA also reviewed these rules to determine if any other corrections or clarifications were needed pursuant to other Sections the Clean Air Act. As described below, based on all these reviews, the EPA has determined it is appropriate and necessary to promulgate some amendments to these rules.

2. Summary of the Major Provisions of the Regulatory Actions

With regard to the National Emissions Standards for Chromium Emissions from Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks, based on the reviews under Sections 112(d)(6) and 112(f), the EPA has determined it is appropriate to promulgate emissions limits and surface tension limits that are moderately lower than the limits in the current regulation for new and existing hard chromium electroplating, decorative chromium electroplating, and chromium anodizing sources. These amendments will reduce chromium emissions (a known human carcinogen) and the risk associated with those emissions. This action also includes housekeeping requirements to minimize fugitive emissions from affected sources. In addition, this action eliminates the use of fume suppressants that contain perfluorooctane sulfonic acid (PFOS), which has been shown to be persistent, bioaccumulative and toxic. Finally, this action amends the requirements for testing, monitoring, reporting, and recordkeeping for consistency with the other requirements of the NESHAP.

With regard to the National Emissions Standards for Hazardous Air Pollutants for Steel Pickling—HCl Process Facilities and Hydrochloric Acid Regeneration Plants, the Agency has determined that no amendments are needed based on the risk and technology reviews under Sections 112(d)(6) and 112(f) of the CAA. However, EPA identified two areas where amendments were needed to ensure the rules were meeting requirements of Sections 112(d)(2) and 112(d)(3). First, this action eliminates an alternative compliance option that was inconsistent with the requirements of CAA section 112(d)(2) and (3). Secondly, we are adding provisions to require the emission limits of the rule to apply at all times, including during periods of startup, shutdown and malfunction.

3. Costs and Emissions Reductions

Table 2 summarizes the costs and emissions reductions for this action. See section V of this preamble for further discussion of the costs and impacts.

TABLE 2—SUMMARY OF THE ESTIMATED COSTS AND EMISSIONS REDUCTIONS FOR THE FINAL CHROMIUM ELECTROPLATING NESHAP AND FINAL STEEL PICKLING NESHAP AMENDMENTS

Source category	Number of affected plants	Capital costs $	Annualized costs $/yr	Emissions reductions lbs/yr
Chromium Electroplating NESHAP				
Large hard chromium electroplating	57	$6,377,000	$1,686,000	148
Small hard chromium electroplating	91	1,424,000	476,000	33
Decorative chromium electroplating	313	163,000	166,000	35
Chromium anodizing	74	235,000	51,000	8
Total	535	8,200,000	2,380,000	224
Steel Pickling NESHAP				
Hydrochloric acid regeneration facilities	1	100,000–200,000	11,419–22,837	30,000

B. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action are shown in Table 3 of this preamble.

Table 3 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.

If you have any questions regarding the applicability of any aspect of these NESHAP, please contact the appropriate person listed in Table 1 of this preamble in the preceding **FOR FURTHER INFORMATION CONTACT** section.

TABLE 3—NESHAP AND INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

NESHAP and Source Category		NAICS Code [1]	MACT Code [2]
Chromium Electroplating NESHAP, Subpart N	Chromium Anodizing Tanks	332813	1607
	Decorative Chromium Electroplating	332813	1610
	Hard Chromium Electroplating	332813	1615
Steel Pickling—HCl Process Facilities And Hydrochloric Acid Regeneration Plants NESHAP, Subpart CCC		3311, 3312	0310

[1] North American Industry Classification System.
[2] Maximum Achievable Control Technology.

C. Where can I get a copy of this document and other related information?

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 by the EPA Administrator, a copy of this final action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/atw/rrisk/rtrpg.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 November 19, 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 Information

A. Overview of the Chromium Electroplating and Chromium Anodizing Source Categories

The 1995 Chromium Electroplating NESHAP regulate emissions of chromium compounds from three source categories: Hard chromium electroplating, decorative chromium electroplating, and chromium anodizing. The NESHAP apply to both major sources and area sources. The NESHAP were promulgated on January 25, 1995, (60 FR 4963) and codified at 40 CFR part 63, subpart N. We amended the NESHAP to address issues related to changes in control technology, monitoring and implementation on July 19, 2004 (69 FR 42885).

1. Hard Chromium Electroplating

The Hard Chromium Electroplating source category consists of facilities that plate base metals with a relatively thick layer of chromium using an electrolytic process. Hard chromium electroplating provides a finish that is resistant to wear, abrasion, heat, and corrosion. These facilities plate large cylinders and industrial rolls used in construction equipment and printing presses, hydraulic cylinders and rods, zinc die castings, plastic molds, engine components, and marine hardware.

The NESHAP distinguish between large hard chromium electroplating facilities and small hard chromium electroplating facilities. Large hard chromium electroplating facilities are defined as any such facility with a cumulative annual rectifier capacity equal to or greater than 60 million ampere-hours per year (amp-hr/yr). Small hard chromium electroplating facilities are defined as any facility with a cumulative annual rectifier capacity less than 60 million amp-hr/yr. The 1995 NESHAP require all affected tanks located at large hard chromium electroplating facilities to meet an emissions limit of 0.015 milligrams of total chromium per dry standard cubic meter (mg/dscm). Alternatively, large hard chromium facilities also can comply with the NESHAP by maintaining the surface tension in affected tanks equal to or less than 45 dynes per centimeter (dynes/cm), if measured using a stalagmometer, or 35 dynes/cm, if measured using a tensiometer. Compliance with the applicable surface tension limit ensures compliance with the emission limit.

The Chromium Electroplating NESHAP require affected tanks at existing small hard chromium electroplating facilities to meet an emissions limit of 0.030 mg/dscm and affected tanks at new small hard chromium electroplating facilities to meet a limit of 0.015 mg/dscm.

Alternatively, these sources have the option of complying with surface tension limits equal to or less than 45 dynes per centimeter (dynes/cm), if measured using a stalagmometer, or 35 dynes/cm, if measured using a tensiometer. Under the current NESHAP, any small hard chromium electroplating tank for which construction or reconstruction was commenced on or before December 16, 1993 (i.e., the proposal date for the original NESHAP), is subject to the existing source standards, and any small hard chromium electroplating tank constructed or reconstructed after December 16, 1993, is subject to new source standards.

We estimate that there currently are approximately 188 large hard chromium electroplating facilities and 394 small hard chromium electroplating facilities in operation in the U.S. outside of California. Of the 394 small hard chromium electroplating facilities, we estimate that 131 of these facilities have one or more tanks that are subject to the new source standards, and the affected sources at the other 263 facilities are subject to the existing source standards. Additionally, there are about 70 hard chromium electroplating facilities operating in California.

2. Decorative Chromium Electroplating

The Decorative Chromium Electroplating source category consists of facilities that plate base materials such as brass, steel, aluminum, or plastic with layers of copper and nickel, followed by a relatively thin layer of chromium to provide a bright, tarnish- and wear-resistant surface. Decorative chromium electroplating is used for items such as automotive trim, metal furniture, bicycles, hand tools, and plumbing fixtures. We estimate that there currently are approximately 517 decorative chromium electroplating plants in operation in the U.S. The 1995 NESHAP require all existing and new decorative chromium electroplating sources to meet a total chromium emissions limit of 0.01 mg/dscm or meet the surface tension limits of 45 dynes/cm, if measured using a stalagmometer, or 35 dynes/cm, if measured using a tensiometer.

3. Chromium Anodizing

The Chromium Anodizing source category consists of facilities that use chromic acid to form an oxide layer on aluminum to provide resistance to corrosion. The chromium anodizing process is used to coat aircraft parts (such as wings and landing gears) as well as architectural structures that are subject to high stress and corrosive conditions. We estimate that there currently are about 170 chromium anodizing plants in operation in the U.S. The NESHAP require all existing and new chromium anodizing sources to meet a total chromium emissions limit of 0.01 mg/dscm, or meet the surface tension limits of 45 dynes/cm, if measured using a stalagmometer, or 35 dynes/cm, if measured using a tensiometer.

B. Summary of the Proposed Amendments to the Chromium Electroplating and Chromium Anodizing Source Categories

1. The October 2010 Proposal

In 2010, pursuant to section 112(f)(2) of the CAA, we evaluated the residual risk associated with the NESHAP. At that time, we also conducted a technology review, as required by section 112(d)(6). Based on the results of our initial residual risk and technology reviews, we proposed on October 21, 2010 (75 FR 65071), that the risks due to HAP emissions from these source categories were acceptable. The basis for this decision is explained in the October 21, 2010 **Federal Register** Notice. Furthermore, we proposed that no additional controls were necessary to provide an ample margin of safety (AMOS) to protect public health or to prevent an adverse environmental effect because we concluded that the costs of the options analyzed were not reasonable considering the emissions and risk reductions potentially achieved with the controls. Thus, we did not propose to revise the NESHAP under 112(f)(2). However, as explained in that proposal publication, we remained concerned about the potential cancer risks due to emissions from these source categories and asked for additional information and comments on this issue. See 75 FR 65071.

As a result of our technology review in 2010, we proposed the following amendments to the NESHAP for all three source categories:

- Incorporate housekeeping practices into 40 CFR 63.342(f); and,
- Phase out the use of wetting agent fume suppressants (WAFS) that use perfluorooctane sulfonic acid (PFOS);

We proposed the housekeeping practices because they will help reduce and minimize fugitive emissions of chromium compounds from chromium electroplating and anodizing facilities and we had determined at the time of the proposal that they could be implemented at relatively low costs. We proposed to revise the rule to no longer allow the addition of PFOS-based WAFS to tanks as a method to meet the MACT requirements for these source categories. The basis for this proposal is described in the October 2010 **Federal Register** Notice (75 FR 65068). We explained that alternatives to PFOS-based WAFS had been successfully used in the hard and decorative chrome source categories and stated that while alternatives had not been used extensively in chromium anodizing, we were unaware of any technical reason that precluded such use. We specifically solicited comment on this issue.

We also proposed some additional changes in the 2010 proposal under Section 112(d)(2) and (d)(3), including:

- Revise the startup, shutdown, and malfunction (SSM) provisions in the rule;
- Revise the monitoring and testing requirements; and
- Make technical corrections to the NESHAP.

The proposed changes to the SSM provisions will ensure that the standards apply at all times, even during periods of malfunction. Regarding the monitoring and testing requirements, we proposed to revise the compliance provisions for multiple sources controlled by a common add-on air pollution control device, clarify that testing can be performed by either Method 306 or Method 306A, revise Method 306B to clarify that the method also applies to hard chromium electroplating tanks and include procedures for checking the accuracy of, and cleaning of, a stalagmometer (See 75 FR 65095 for a more detailed discussion of the proposed monitoring revisions).

We also proposed to add a provision to provide an affirmative defense against civil penalties for violations of emission standards caused by malfunctions, as well as criteria for establishing the affirmative defense, which is the same affirmative defense provision we have proposed or promulgated in several other recent MACT rules.

In our 2010 proposal, we provided further explanation of the basis for proposing these amendments to the NESHAP pursuant to CAA section 112(d)(6). See 75 FR 65093. We proposed that existing sources could not use PFOS-based WAFS 3 years after publication of the final rule in the **Federal Register** and that new sources cannot use PFOS-based WAFS as a method to meet the NESHAP requirements.

2. The February 8, 2012 Supplemental Proposal

In response to the 2010 proposal, several commenters expressed concern that the data set used in the risk assessment was not sufficient and not

representative of the current chromium electroplating industry. Additional data were submitted during the comment period and we also worked with industry and states to gather additional data. Based on the new data, we performed a new risk and technology review for all three source categories.

Our February 2012 supplemental proposal (77 FR 6628) presented the results of the new risk assessment. Based on that assessment, we proposed that risks due to HAP emissions from each of the three chromium electroplating and anodizing source categories were acceptable since the actual and allowable emissions of HAP pose cancer risks below 100-in-1 million, and because a number of the other risk metrics did not indicate high risk concerns. For hard chromium electroplating, we estimated that the maximum individual cancer risk (MIR) was 20-in-1 million based on actual emissions and that about 130,000 people were exposed to risks greater than 1-in-1 million, for decorative chromium electroplating we estimated that the MIR was 10-in-1 million based on actual emissions and that about 43,000 people were exposed to risks greater than 1-in-1 million, and for the chromic acid anodizing source category we estimated that the MIR was 5-in-1 million based on actual emissions and that about 5,000 people were exposed to risks greater than 1-in-1 million. Moreover, the potential risks due to allowable emissions were estimated to be up to 50-in-1 million for hard chromium electroplating, 70-in-1 million for decorative chromium electroplating, and 60-in-1 million for chromic acid anodizing. After proposing that the risks posed by each source category were acceptable, we evaluated potential control options under Section 112(f) for each source category to determine whether additional controls were necessary to provide an ample margin of safety or to prevent an adverse environmental effect. We identified cost-effective controls that would lower emissions and reduce risks. Therefore, in the February 8, 2012, supplemental proposal, we proposed pursuant to CAA section 112(f)(2) to tighten the emissions limits for affected sources. For existing large hard chromium electroplating tanks, we proposed tightening the emissions limit from 0.015 mg/dscm to 0.011 mg/dscm. For existing small hard chromium electroplating sources, we proposed tightening the emissions limit from 0.030 mg/dscm to 0.015 mg/dscm. For existing decorative chromium electroplating and chromium anodizing sources, we proposed tightening the emissions limit from 0.010 mg/dscm to 0.007 mg/dscm. For all new sources, we proposed tightening the emissions limit to 0.006 mg/dscm. We explained that these emission limits were cost effective.

In our supplemental proposal, we also proposed to require under CAA section 112(d)(6) the same limits that we proposed would provide an ample margin of safety because the limits reflect developments in practices, processes or control technologies and are cost-effective. See 77 FR 6638–45.

We also proposed under both CAA section 112(f)(2) and section 112(d)(6) that sources could instead demonstrate compliance by maintaining surface tension limits of 40 dynes/cm, if measured using a stalagmometer, and 33 dynes/cm, if measured using a tensiometer. These limits are tighter than those currently in the NESHAP, which are 45 dynes/cm, if measured using a stalagmometer, and 35 dynes/cm, if measured using a tensiometer. The proposed surface tension limits would ensure that the alternative compliance option is at least as stringent as the concentration based emissions limits described above. 77 FR at 6644–45. For more information regarding the relationship between surface tension and emissions see the *Development of Revised Surface Tension Limits for Chromium Electroplating and Anodizing Tanks Controlled with Wetting Agent Fume Suppressants* document, which is available in the docket.

We estimated that these proposed emissions limits and surface tension limits would reduce the cancer risks, cancer incidence, and the number of people exposed to risks greater than 1-in-1 million due to emissions of hexavalent chromium from this industry by 25 to 50 percent. 77 FR at 6648–49.

We proposed that existing sources would need to meet the limits no later than 2 years after the effective date of the final rule. Section 112(f)(4) generally provides that a standard promulgated pursuant to CAA section 112(f)(2) applies 90 days after the effective date, but further provides for a compliance period of up to 2 years where the Administrator finds that such time is necessary for the installation of controls and that steps will be taken during that period to assure protection to health from imminent endangerment. In the supplemental proposal, we explained that a 2-year compliance period was necessary for facilities to determine if they meet the proposed emissions limits, schedule a compliance test, perform an engineering analysis to determine the control options, and install and test new emissions control equipment. We further proposed that new sources must comply with the emission limits or surface tension limits upon start-up. See 77 FR 6649.

As stated in the proposed preamble, the EPA is taking a step to increase the ease and efficiency of data submittal and data accessibility. Specifically, the EPA is requiring owners and operators of Chrome Electroplating/Steel Pickling facilities to submit electronic copies of required performance test reports.

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

The requirement to submit performance test data electronically to the EPA does not create any additional performance testing and will apply only to those performance tests conducted using test methods that are supported by the ERT. A listing of the pollutants and test methods supported by the ERT is available at the previously mentioned ERT Web site. The EPA believes, through this approach, industry will save time in the performance test submittal process. Additionally this rulemaking benefits industry by cutting back on recordkeeping costs as the performance test reports that are submitted to the EPA using CEDRI are no longer required to be kept on site.

As mentioned in the proposed preamble, State, local and tribal agencies will benefit from more streamlined and accurate review of electronic data that will be available on the EPA WebFIRE database. Additionally performance test data will become available to the public through WebFIRE. Having such data publicly available enhances transparency and accountability. The major advantages of electronic reporting are more fully explained in the proposed preamble.

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. See

77 FR 6649–50. We proposed that the revised reporting requirements would apply upon promulgation of the final rule.

C. Overview of the Steel Pickling Source Category

Steel pickling is a treatment process in which the heavy oxide crust or mill scale that develops on the steel surface during hot forming or heat treating is removed chemically in a bath of aqueous acid solution. There are two specific processes regulated under the Steel Pickling NESHAP. Pickling is a process applied to metallic substances that removes surface impurities, stains, or crusts to prepare the metal for subsequent plating (e.g., with chromium) or other treatment, such as galvanization or painting. A pickling line is defined in the rule as using an acid solution in any tank in which hydrochloric acid is at a concentration of 6 percent by weight or greater and has a temperature of 100 °F or greater. An acid regeneration plant is defined in the rule as the equipment and processes that regenerate fresh hydrochloric acid (HCl) pickling solution from spent pickle liquor using a thermal treatment process. The HAP emission points from the steel pickling process include steel pickling baths, steel pickling sprays, and tank vents. The HAP emission point from acid regeneration plants is the spray roaster.

We estimate that there are approximately 100 facilities subject to the Steel Pickling NESHAP. Many of these facilities are located adjacent to integrated iron and steel manufacturing plants or electric arc furnace steelmaking facilities (minimills) that produce steel from scrap. Acid Regeneration facilities may or may not be located at steel pickling operations.

D. Summary of the Proposed Amendments to the Steel Pickling Source Category

In 2010, pursuant to section 112(f)(2) of the CAA, we evaluated the residual risk associated with the NESHAP. We also conducted a technology review, as required by section 112(d)(6) of the CAA. Based on our risk analysis, we determined that there were no cancer risks attributable to emissions from the steel pickling source category. We also estimated the maximum chronic non-cancer TOSHI value to be 2 based on emissions of chlorine and the maximum off-facility-site acute Hazard Quotient (HQ) value could be up to 0.4, based on actual emission levels and the reference exposure level (REL) value for chlorine. 75 FR at 65122–24. We proposed on October 21, 2010 that the risks were acceptable based on our determination that facilities in this source category emit no HAPs that are carcinogens and because the acute risks were low. While the chronic non-cancer TOSHI level for one facility exceeded the reference level, we noted that this facility has had compliance issues with the standard and that the actual emissions we relied on for this facility included emissions in excess of what is allowed under the MACT standard. We estimate that if emissions were maintained at levels equal to or lower than the level allowed by the MACT limit (6 ppm) then the TOSHI would be no higher than 1. The next highest HI from any facility in the source category is 0.1.

We identified one development in practices, processes or control technologies for this source category, but determined that it was not technically feasible for the industry. 75 FR at 65124. Thus, we proposed that no amendments were necessary under both the second part of the section 112(f) review, determining whether the standard provides an ample margin of safety and prevents an adverse environmental effect, and for the 112(d)(6) review. 75 FR at 65124. However, under section 112(d)(2) and 112(d)(3), we proposed to eliminate the startup, shutdown and malfunction (SSM) exemption in the Steel Pickling NESHAP in light of the court's decision in Sierra Club v. EPA (Sierra Club v. EPA, 551 F.3d 1019 (D.C. Cir. 2008) 130 S. Ct. 1735 (2010)). We proposed several revisions to the regulations regarding SSM, including:

- Revising Table 1 to indicate that the requirements in 40 CFR 63.6(e) of the General Provisions, regarding the "duty to minimize" emissions do not apply and instead proposed to incorporate it in 40 CFR 63.1159(c).
- Removing the SSM Plan requirement requiring affected sources to calculate their emissions during startup and shutdown and to maintain records of the startup and shutdown emission calculations.
- Revising the SSM-associated monitoring, recordkeeping and reporting requirements to require reporting and recordkeeping for periods of malfunction.
- Adding provisions to provide an affirmative defense against civil penalties for violations of emission standards caused by malfunctions, as well as criteria for establishing the affirmative defense.

In the February 2012 supplemental proposal (77 FR 6628) we proposed two additional actions for the Steel Pickling source category. First, we proposed to remove a compliance alternative established in the original MACT rule. The alternative compliance option allowed existing HCl regeneration facilities to request approval for an alternative source-specific chlorine concentration standard from their permitting authority. We stated that we believe that this alternative compliance option was not appropriate under CAA sections 112(d)(2) and (3) and that the option had been adopted inappropriately. Second, we proposed to require electronic reporting for the Steel Pickling and HCl Acid Regeneration source category similar to that described above for the chromium electroplating and chromium anodizing source categories and for the same reasons.

III. Summary of the Final Rule

A. What are the final rule amendments for the Chromium Electroplating and Chromium Anodizing source categories?

1. Risk and Technology Review

For all three chromium electroplating and chromium anodizing source categories, we are finalizing the emission and surface tension limits as proposed in the supplemental proposal under Sections 112(d)(6) and 112(f)(2) of the Clean Air Act. However, as noted in the following paragraphs, we performed additional analyses based on issues raised and information submitted during the comment period, which add further support for this final action.

Additional information on emissions and controls from chromium electroplating and chromic acid anodizing sources was submitted to EPA during the comment period, and we also obtained additional data and information from some States and industry shortly after the close of the comment period. The information supported the data and analyses we had performed to develop the emissions limits for the supplemental proposal. For example, we obtained data from two additional chromic acid anodizing plants that showed they had emissions well below the limits we are promulgating and that indicates the anodizing plants can easily meet the limits with readily available common control technologies. We also obtained additional data from hard chromium electroplating plants that shows even more plants than we estimated in the proposal are already meeting the lower emissions limits.

We also performed new analyses of the costs of the proposed requirements and the emissions reductions that would be achieved based on the information that became available after we issued the supplemental proposal.

The revised costs and emissions reductions are similar to those presented at proposal (77 FR 6628). For example, the overall total estimated annualized cost in the supplemental proposal was $3,000,000 and cost-effectiveness was estimated to be $14,900 per pound of hexavalent chromium emissions reductions and we estimated the proposed changes would reduce emissions by 208 pounds per year. We now estimate the overall total annualized cost of the final rule is $2,400,000, that the cost-effectiveness is approximately $11,000 per pound of hexavalent chromium emissions reductions, and that the final rule will achieve 224 pounds per year of hexavalent chromium reductions. Our full analysis can be found in *Revised Procedures for Determining Control Costs and Cost Effectiveness for Chromium Electroplating and Anodizing,* which is available in the docket.

With regard to our review under Section 112(f), we continue to conclude that risks are acceptable for all 3 source categories since the cancer MIRs for each of the source categories are below 100-in-1 million, and because a number of the other risk metrics do not indicate high risk concerns. However, as explained below, we are promulgating standards under Section 112(f) to provide an ample margin of safety.

Regarding the standards proposed under Section 112(f)(2), several commenters claimed that, as part of the ample margin of safety analysis included in the proposed rule, we did not evaluate the health impacts (e.g., reduced risk of cancer) of the various options we considered. The comments are summarized in Section IV of this notice and in the Responses to Comments (RTC) document, which is available in the docket.

As set forth in the Benzene NESHAP, in the ample margin of safety decision process, the agency again considers all of the health risks and other health information considered in the first step (acceptability determination). Beyond that information, additional factors relating to the appropriate level of control are considered, including costs and economic impacts of controls, technological feasibility, uncertainties and any other relevant factors.

In the supplemental proposal addressing our risk review for the chromium electroplating and anodizing source categories, under the ample margin of safety analysis, we evaluated and presented various emission control options, and the costs and economic impacts associated with those options. While we summarized the risk reductions that would be achieved with the proposed limits, we did not provide information regarding the risk reductions that could be achieved by control options that we did not propose to adopt. In response to the comments we received, we also evaluated the risk reductions that would be achieved by each technically feasible option for each of the chromium electroplating and anodizing source categories and subcategories (i.e., large hard chromium electroplating, small hard chromium electroplating, decorative electroplating and chromic acid anodizing). The results are summarized below.

Baseline Risks for Hard Chromium Electroplating. For the Hard Chromium Electroplating source category (including large and small hard chromium electroplating sources), the MIR due to actual emissions is estimated to be 20-in-1 million, and the cancer incidence is estimated to be 0.05 cases per year. The MIR due to allowable emissions is estimated to be 50-in-1 million, and the cancer incidence based on allowable emissions is estimated to be 0.2 cases per year. Based on actual emissions, approximately 1,100 people are estimated to have cancer risks at or above 10-in-1 million, and approximately 130,000 people are estimated to have cancer risks at or above 1-in-1 million. We estimate that about two-thirds of the population risks are due to large hard chromium sources and the remainder of the population risks are due to small hard chromium sources. We also estimate that the potential is low for chronic and acute non-cancer health effects, and for multipathway risks. As discussed in the preamble to the supplemental proposed rule, we conclude that the risks from this source category are acceptable.

Large Hard Chromium Electroplating Emission Limits

For the large hard chromium sources, we evaluated three control options in the supplemental proposal. The first option, which is the option we proposed and are finalizing today, would be to lower the chromium emissions limit for existing sources from 0.015 mg/dscm to 0.011 mg/dscm. The second option was to lower the limit to 0.0075 mg/dscm, and the third option was to lower the limit to 0.006 mg/dscm. The results of our cost and risk analyses for large hard chromium sources are summarized in Table 4.

TABLE 4—SUMMARY OF COSTS AND RISK REDUCTIONS FOR THE VARIOUS OPTIONS CONSIDERED FOR LARGE HARD CHROMIUM ELECTROPLATING

Option	Emission reductions in lbs/yr	Total emissions in lbs/yr	MIR [1] (in-a-million)		Incidence (cases/yr)	Number of people with risk > 1-in-1 million	Number of people w/ risk > 10-in-1 million	Annualized costs	Cost-effectiveness (per lb)
			Actual	Allowable					
Baseline: current situation	0	454	20	50	0.03	88,000	740	0	NA
Option 1—Final: limit of 0.011 mg/dscm	148	306	[2] 20	40	0.02	59,000	500	$1.7 M	$11,000
Option 2: limit of 0.0075 mg/dscm	169	285	10	30	[2] 0.02	55,000	470	$4.1 M	$24,700
Option 3: limit of 0.006 mg/dscm	180	274	8	20	[2] 0.02	53,000	450	$5.3 M	$29,900

[1] MIR estimates are derived from estimates of actual and allowable emissions. Population risk estimates are derived from estimates of actual emissions.
[2] There are further risk reductions associated with this option compared to the previous option, but they are not large enough to change the risk values as presented to one significant figure.

We also estimated impacts of Option 1 to small businesses, and found that most facilities would have a costs-to-sales ratio of less than 1 percent. However, we estimated that 6 plants could have costs-to-sales ratios up to 9 percent. (See Economic Impact Analysis for Risk and Technology Review: Chromium Electroplating and Chromic Acid Anodizing Source Categories, which can be found in the docket for this action.) For the other two options (Options 2 and 3), we did not quantify the impacts to small businesses, however, they would both pose impacts to a larger number of small businesses since they would impose costs on more facilities and almost all facilities within this category are small businesses. As shown in Table 4, Option 1 also achieves meaningful reductions in risks associated with exposure to a known human carcinogen, including an estimated 30 percent reduction in the

MIR, cancer incidence, and the numbers of people with risks at or above 1-in-1 million and 10-in-1 million. For the other two options (Options 2 and 3), the estimated annualized costs and cost-effectiveness values were more than double those of Option 1 and a significantly greater number of small businesses would be impacted, with only small additional risk reductions achieved beyond Option 1. Although Options 2 and 3 reduce the baseline MIR by 50 percent or more, the baseline MIR is already considerably below 100-in-1 million, and the options reduce incidence and population risks only slightly. Considering the cost, economic, and risk impacts discussed above, we conclude that Option 1 provides an ample margin of safety.

Furthermore, in the 2010 proposal (75 FR 65068), we considered the option of requiring controls similar to standards adopted in California, which would essentially require facilities to install high efficiency particulate air (HEPA) filters on all hard chromium plants. As described in the 2010 proposal, the overall costs for that option were significantly higher than the other options described above, and would have resulted in much greater economic impacts to small businesses. Furthermore, based on more recent analyses, we estimate that the cost effectiveness of requiring HEPA filters on all large hard chromium plants would be at least $27,000 per pound. (see *Revised Procedures for Determining Control Costs and Cost Effectiveness for Chromium Electroplating and Anodizing,* which is available in the docket). With regard to health factors, requirements similar to the California standards would likely reduce risks to below 1-in-1 million for all hard chromium plants. However, given the high overall costs and economic impacts, we have determined that it is not appropriate to require those controls in order to provide an ample margin of safety to protect public health or to prevent an adverse environmental effect. Therefore, based on all our analyses and after weighing all the factors, we are promulgating the chromium emissions limit of 0.011 mg/dscm, as proposed in February 2012 (77 FR 6628) for existing large hard chromium electroplating sources because we believe that limit will provide an ample margin of safety to protect public health and prevent an adverse environmental effect.

With regard to new sources, we proposed a limit of 0.006 mg/dscm. The rationale for choosing 0.006 mg/dscm is described in detail in the supplemental proposal. After considering public comments and additional analyses, we are finalizing this limit of 0.006 mg/dscm for new large hard chromium plants because this is the lowest level that can be reliably achieved cost-effectively, such as allowing plants the flexibility to use add-on controls or WAFS to comply. This limit will ensure that the risks posed by any new sources will be acceptable and the standard will provide an ample margin of safety to protect public health and prevent an adverse environmental effect.

Small Hard Chromium Electroplating Emission Limits

For small hard chromium electroplating sources, we also evaluated the costs and risk reductions that would be achieved for three main control options. The first option, which is the option we proposed and are finalizing today, would be to lower the chromium emissions limit for pre-1995 sources from 0.03 mg/dscm to 0.015 mg/dscm. The second option was to lower the limit to 0.01 mg/dscm, and the third option was to lower the limit to 0.006 mg/dscm. The basis for evaluating these options is explained further in the supplemental proposal. (77 FR 6628) The results are summarized in Table 5.

TABLE 5—SUMMARY OF COSTS AND RISK REDUCTIONS FOR THE VARIOUS OPTIONS CONSIDERED FOR SMALL HARD CHROMIUM ELECTROPLATING

Option	Emission reductions in lbs/yr	Total emissions in lbs/yr	MIR [1] (in-a-million)		Incidence (cases/yr)	Number of people with risk > 1-in-1 million	Number of people with risk > 10-in-1 million	Annualized costs	Cost-effectiveness (per lb)
			Actual	Allowable					
Baseline: current situation	0	223	20	50	0.02	43,300	360	0	NA
Option 1—Final (0.015 mg/dscm)	33	190	10	30	0.01	36,800	306	$0.5 M	$15,000
Option 2: 0.01 mg/dscm	71	152	7	20	[2] 0.01	29,000	245	$1.5 M	$21,000
Option 3: 0.006 mg/dscm	116	107	4	10	0.008	22,500	190	$2.2 M	$19,300

[1] MIR estimates are derived from estimates of actual and allowable emissions. Population risk estimates are derived from estimates of actual emissions.
[2] The incidence estimate under Option 2 is less than the incidence estimate under option 1, but the estimates are reported as the same when rounded to one significant figure.

We also estimated the impacts of Option 1 to small businesses, and found that most facilities would have a costs-to-sales ratio of less than 1 percent. However, we estimated that 3 plants could have costs-to-sales ratios of about three percent. For the other two options (Options 2 and 3), we did not quantify the impacts to small businesses; however, we know Options 2 and 3 would pose impacts to a larger number of small businesses.

Option 1, as shown in Table 5, achieves approximately a 50 percent reduction in the MIR and cancer incidence associated with exposure to a known human carcinogen, and a 20 percent reduction in the numbers of people with risks at or above 1-in-1 million and 10-in-1 million, for $500,000 in annualized costs. Options 2 and 3 achieve similar reductions in incidence and population risks, but the annualized costs were three and four times higher, respectively, than those of Option 1, and substantially more small businesses would be impacted. Although Options 2 and 3 reduce the baseline MIR by more than half, the baseline MIR is already considerably below 100-in-1 million. Considering the cost, economic, and risk impacts discussed above, we conclude that Option 1 provides an ample margin of safety to protect public health.

Furthermore, as explained in the 2010 proposal, we considered the option of requiring controls similar to the California standards, which would have essentially required all hard chromium electroplating facilities to install HEPA filters. As described in the 2010 proposal, the estimated total capital and annualized costs for that option were much higher than the other options described above and would have imposed much more significant economic impacts to small businesses. Furthermore, based on more recent analyses, we estimate that the cost effectiveness of requiring HEPA filters on all small hard chromium plants would be at least $42,700 per pound. (see *Revised Procedures for Determining Control Costs and Cost Effectiveness for Chromium Electroplating and Anodizing,* which is available in the

docket). With regard to health factors, requiring controls similar to the California standards would likely reduce risks to below 1-in-1 million for all hard chromium plants. However, given the high overall costs, we have determined that it is not appropriate to require controls similar to those in California in the national rule.

In summary, based on all our analyses and after weighing all the factors, we are promulgating the chromium emissions limit of 0.015 mg/dscm, as proposed in the supplemental proposal notice (77 FR 6628) for existing small hard chromium electroplating sources.

With regard to new sources, as described in detail in the supplemental proposal, we proposed a chromium emissions limit of 0.006 mg/dscm. The rationale for choosing 0.006 mg/dscm is described in detail in the supplemental proposal. After considering public comments and additional analyses, we are finalizing this limit of 0.006 mg/dscm for new small hard chromium plants because this is the lowest level that can be reliably achieved cost-effectively, such as allowing plants the flexibility to use add-on controls or WAFS to comply. This limit will ensure that the risks posed by any new sources will be acceptable and the standard will provide an ample margin of safety to protect public health and prevent an adverse environmental effect.

Decorative Chromium Electroplating Emission Limits

For the Decorative Chromium Electroplating source category, the MIR due to actual emissions is estimated to be 10-in-1 million, and the cancer incidence is estimated to be 0.02 cases per year. The MIR due to allowable emissions is estimated to be 70-in-1 million, and the cancer incidence is estimated to be 0.08 cases per year. Based on actual emissions, approximately 100 people are estimated to have cancer risks at or above 10-in-1 million, and approximately 43,000 people are estimated to have cancer risks at or above 1-in-1 million. We also estimate that the potential is low for chronic and acute non-cancer health effects, and for multipathway risks. As discussed in the preamble to the supplemental proposed rule, we conclude that the risks from this source category are acceptable.

With regard to control options, as explained in the preamble of the supplemental proposal, we evaluated possible limits within the range of 0.006 to 0.01 mg/dscm under the technology review and risk reviews. The current standard is 0.01 mg/dscm, and we considered this as the upper limit to be considered. As described in the supplemental proposal, we decided that 0.006 mg/dscm should be the lower end of the range of limits considered because most plants rely on fume suppressants to limit emissions and 0.006 mg/dscm was the lowest concentration that we estimated could reliably be achieved by limiting surface tensions to 33 dynes/cm (as measured with tensiometer) and 40 dynes/cm (as measured with a stalagmometer). However, a portion of the decorative plating sources rely on add-on controls to comply with the NESHAP. Therefore, we also evaluated the emissions levels being achieved by decorative electroplating plants that rely on add-on controls. Based on data we have for 20 tanks at 17 facilities, the emissions concentrations from these 20 tanks are all less than 0.007 mg/dscm. The highest value is 0.0066 mg/dscm. Two of these tanks (about 11 percent) have emissions between 0.006 to 0.0066 mg/dscm. The other 15 tanks have emissions below 0.005 mg/dscm. After evaluating this range, as described in the proposal, we decided to propose an emissions limit of 0.007 mg/dscm, a limit slightly higher than the emissions being achieved by the highest emitting facilities in our data set to minimize the need for additional add-on controls in this source category. Based on the data we have, a limit of 0.006 mg/dscm could result in some plants needing to retrofit their add-on controls which would result in significantly higher costs for those facilities. With regard to reductions, we estimate this option would achieve reductions in overall emissions of far less than 15 percent compared to the 0.007 mg/dscm limit. Therefore, we did not further evaluate the 0.006 mg/dscm limit for existing sources.

As described above, for decorative chromium electroplating sources, we evaluated the costs and risk reductions that would be achieved under one control option for existing sources. That option, which we are finalizing today as proposed, is to lower the emissions limit for existing sources from 0.01 mg/dscm to 0.007 mg/dscm. The basis for evaluating this option is explained further in the supplemental proposal. The results of our cost and risk analyses for decorative chromium electroplating sources are summarized in Table 6.

TABLE 6—SUMMARY OF COSTS AND RISK REDUCTIONS FOR THE VARIOUS OPTIONS CONSIDERED FOR DECORATIVE CHROMIUM ELECTROPLATING

Option	Emission reductions in lbs/yr	Total emissions in lbs/yr	MIR [1] (in-a-million)		Incidence (cases/yr)	Number of people with risk > 1-in-1 million	Number of people with risk > 10-in-1 million	Annualized costs	Cost-effective-ness (per lb)
			Actual	Allowable					
Baseline: Current situation	0	222	10	70	0.02	43,000	100	0	NA
Option 1 (0.007 mg/dscm)	35	187	7	50	[2] 0.02	36,000	80	$170K	$5,000

[1] MIR estimates are derived from estimates of actual and allowable emissions. Population risk estimates are derived from estimates of actual emissions.
[2] The incidence estimate under Option 1 is less than the baseline estimate, but the estimates are reported as the same when rounded to one significant figure.

With regard to the risk reductions achieved by the proposed lower limit of 0.007 mg/dscm, we estimate that the MIR based on actual emissions of hexavalent chromium, a known human carcinogen, would be reduced by about 30%, and the total estimated cancer incidence, the number of people estimated to have cancer risks at or above 10-in-1 million and the number of people estimated to have risks at or above 1-in-1 million would be reduced by about 15 percent. The MIR based on allowable emissions will be reduced from 70-in-1 million to 50-in-1 million. We also considered a limit of 0.006 mg/dscm; however, reducing the limit from 0.007 to 0.006 mg/dscm would provide minimal additional risk reduction and would likely result in more sources needing to upgrade add-on controls which would result in significantly higher costs. Therefore, after considering all the costs, economic and health factors, and comments, we are promulgating an emissions limit of 0.007 mg/dscm for decorative chromium sources, as proposed in the supplemental proposal (77 FR 6628).

With regard to new sources, as described in detail in the supplemental proposal, we proposed a limit of 0.006 mg/dscm. The rationale for choosing

0.006 mg/dscm is described in detail in the supplemental proposal. After considering public comments and additional analyses, we are finalizing this limit of 0.006 mg/dscm for new decorative chromium electroplating plants because this is the lowest level that can be reliably achieved cost-effectively and while still allowing plants the flexibility to use add-on controls or WAFS to comply. This limit will ensure that the risks posed by any new sources will be acceptable and the standard will provide an ample margin of safety to protect public health and prevent an adverse environmental effect.

Chromic Acid Anodizing Emission Limits

For the Chromic Acid Anodizing source category, the MIR due to actual emissions is estimated to be 5-in-1 million, and the cancer incidence is estimated to be 0.003 cases per year. The MIR due to allowable emissions is estimated to be 60-in-1 million, and the cancer incidence is estimated to be 0.08 cases per year. Based on actual emissions, no people are estimated to have cancer risks at or above 10-in-1 million, and approximately 5,000 people are estimated to have cancer risks at or above 1-in-1 million. We also estimate that the potential is low for chronic and acute non-cancer health effects, and for multipathway risks. As discussed in the preamble to the supplemental proposed rule, we conclude that the risks from this source category are acceptable.

For chromic acid anodizing sources, we evaluated the costs and risk reductions that would be achieved for one control option for existing sources. That option, which we are finalizing today as proposed, is to lower the emissions limit for existing sources from 0.01 mg/dscm to 0.007 mg/dscm. The basis for evaluating this option is explained further in the supplemental proposal. The results of our cost and risk analyses for chromic acid anodizing sources are summarized in Table 7.

TABLE 7—SUMMARY OF COSTS AND RISK REDUCTIONS FOR THE VARIOUS OPTIONS CONSIDERED FOR CHROMIUM ANODIZING

Option	Emission reductions in lbs/yr	Total emissions in lbs/yr	MIR [1] (in-a-million)		Incidence (cases/yr)	Number people with risk > 1-in-1 million	Number people with risk > 10-in-1 million	Annualized costs	Cost-effective-ness (per lb)
			Actual	Allowable					
Baseline: Current situation	0	57	5	60	0.003	5,000	0	NA	NA
Option 1 (0.007 mg/dscm)	8	49	3	40	[2] 0.003	4,000	0	$50K	$6,580

[1] MIR estimates are derived from estimates of actual and allowable emissions. Population risk estimates are derived from estimates of actual emissions.
[2] The incidence estimate under Option 1 is less than the baseline incidence estimate, but the estimates are reported as the same when rounded to one significant figure.

As explained in the supplemental proposal (77 FR 6628), we had less source data for anodizing plants; however, we determined that based on the similarities with decorative chromium sources, it was appropriate to evaluate the same options and also to propose the same limits for anodizing plants as proposed for decorative sources. With regard to the risk reductions achieved by the proposed limit of 0.007 mg/dscm, we estimate that the MIR based on actual emissions of hexavalent chromium, a known human carcinogen, would be reduced to about 3-in-1 million, the total estimated cancer incidence would be reduced by about 15%, and the number of people estimated to have risks at or above 1-in-1 million would be reduced from 5,000 to 4,000. As we did for the decorative chromium electroplating category, we also considered a limit of 0.006 mg/dscm for the anodizing category, however the additional reduction in risk that would be achieved by going from 0.007 to 0.006 would be minimal, and this change would likely result in increased costs. After considering all the costs, economic and health factors, we are promulgating an emissions limit of 0.007 mg/dscm for chromic acid anodizing sources (77 FR 6628).

With regard to new sources, as described in detail in the supplemental proposal, we proposed a limit of 0.006 mg/dscm. The rationale for choosing 0.006 mg/dscm is described in detail in the supplemental proposal. After considering public comments and additional analyses, we are finalizing this limit of 0.006 mg/dscm for new chromic acid anodizing plants because this is the lowest level that can be reliably achieved cost-effectively, such as allowing plants the flexibility to use add-on controls or WAFS to meet this level of emissions and this limit will ensure that the risks posed by any new sources will be acceptable and provide an ample margin of safety to protect public health and prevent an adverse environmental effects.

Conclusion—Emissions Limits

The Agency has determined that the risks due to HAP emissions from these source categories are acceptable. Furthermore, after considering all the health and cost factors described above, the agency has determined that the NESHAP for the hard and decorative chromium electroplating and chromic acid anodizing source categories, with the promulgated changes in today's action (as explained above) will provide an ample margin of safety to protect the public health and will prevent an adverse environmental effect.

We are also revising the standards pursuant to CAA section 112(d)(6). Because it is cost effective to meet the limits we are promulgating under CAA section 112(f), described above, we have also determined it is necessary to revise the NESHAP pursuant to CAA section 112(d)(6) to require such limits.

Housekeeping Requirements

We are also revising the standards pursuant to CAA section 112(d)(6) to include several housekeeping requirements. However, in response to comments we received, we are making several minor revisions to the proposed housekeeping requirements to clarify and simplify those requirements. The revisions are summarized below and described in detail in the RTC document, which is available in the docket.

The housekeeping procedures include storage requirements for any substance that contains hexavalent chromium as a primary ingredient; controls for the dripping of bath solution resulting from dragout; splash guards to minimize overspray and return bath solution to the electroplating or anodizing tank; a requirement to promptly clean up or contain all spills of any substance containing hexavalent chromium; requirements for the routine cleaning or stabilizing of storage and work surfaces, walkways, and other surfaces potentially contaminated with hexavalent chromium; a requirement to install a barrier between all buffing,

grinding, or polishing operations and electroplating or anodizing operations; and requirements for the storage, disposal, recovery, or recycling of chromium-containing wastes. The main changes that were made to the housekeeping requirements since the 2010 proposal based on public comments include removing routine housekeeping measures from recordkeeping, adding that cleanup must be initiated within one hour of the spill, and allowing facilities to collect dragout using other methods when drip trays are not practical. The compliance date for implementing the housekeeping procedures will be 6 months after promulgation of the final amendments. More details on the housekeeping requirements are explained in the 2010 proposal and in the RTC document.

Phase-Out of PFOS WAFS

Also pursuant to CAA section 112(d)(6), we are specifying that PFOS WAFS cannot be added to any affected hard chromium electroplating tank, decorative chromium electroplating tank, or chromium anodizing tank as a method to meet the NESHAP requirements for these source categories. In response to public comments about the effectiveness and feasibility of non-PFOS WAFS, we collected information from several chromium electroplating plants in Minnesota that have been using non-PFOS WAFS for several years, and that information confirmed that the non-PFOS substitutes are effective and feasible alternatives to PFOS-based chemicals. See *Information on non-PFOS Fume Suppressants in Minnesota Chromium Electroplating Facilities.* Further details are also provided in the responses to comments provided in Section IV of this FR notice and in the RTC document.

Other Amendments

We are finalizing the changes to the SSM requirements, electronic reporting requirements, test procedures, and monitoring requirements as proposed. We are also finalizing the addition of a provision to provide an affirmative defense against civil penalties for violations of emission standards caused by malfunctions, as well as criteria for establishing the affirmative defense.

B. What are the effective and compliance dates for the Chromium Electroplating and Chromium Anodizing source category amendments?

The effective date for the final rule amendments is September 19, 2012. The compliance date for implementing the housekeeping requirements is March 19, 2013. The compliance date for the revised emission limits and surface tension limits is September 19, 2014. The compliance date for eliminating the use of PFOS-based fume suppressants is September 21, 2015.

C. What are the final rule amendments for the Steel Pickling source category?

1. Revisions Pursuant to CAA Section 112(d)(2) & (3)

At the time we promulgated the original MACT standard, we also established an alternative compliance option for the steel pickling source category that allowed HCl regeneration facilities to apply for a site specific alternative chlorine concentration standard for existing acid regeneration plants. In this final rule, we are removing the alternative compliance option. After reviewing public comments and evaluating additional information received since proposal, we continue to believe that the alternative compliance option provided in the original rule was not appropriate and therefore should be removed from the rule because it allowed a source to establish a source specific limit which could be less stringent than the MACT Floor level of control. Based on our review and analysis of available information, EPA concludes that the emission limit for chlorine can be met using available control technologies such as alkaline scrubbers, and that this level of control is consistent with the MACT floor level of control established in the original NESHAP. We estimate that the amendment to remove the alternative compliance provision will reduce emissions of chlorine by 15 tons per year (tpy).

2. Risk and Technology Review

As provided in the proposed rule, we are not revising the Steel Pickling NESHAP pursuant to CAA sections 112(f)(2) and 112(d)(6). While the chronic non-cancer TOSHI level for one facility exceeded the reference level, we noted that this facility has had compliance issues with the standard and that the actual emissions we relied on for this facility included emissions in excess of what is allowed under the NESHAP.

Given the amendment to remove the alternative compliance option under Section 112(d)(2) and (d)(3) as described above, and assuming that the one facility will apply the necessary controls to achieve compliance with the NESHAP, we estimate that the maximum chronic non-cancer TOSHI for any facility in the category will be less than 1. Therefore, the maximum TOSHI allowed by the NESHAP will be no higher than 1.

Based on consideration of all the risk assessment results, including the fact that the maximum TOSHI allowed by the rule will be no higher than 1, we conclude that risks are acceptable and that the NESHAP will provide an ample margin of safety given the amendments we are promulgating in this action.

Therefore, we are not amending the NESHAP under Section 112(f) because risks are acceptable and the NESHAP, as revised pursuant to 112(d)(2) and (d)(3), provides an ample margin of safety. We are also not amending the NESHAP under section 112(d)(6) because we have not identified new developments in practices, processes or control technologies. We have determined that the Steel Pickling NESHAP, given the amendments we are promulgating in this action, provide an ample margin of safety to protect public health and prevent an adverse environmental effect, and that there have been no advances in practices, processes, and control technologies feasible for this source category.

3. Electronic Reporting

The final rule amendments require owners and operators of affected facilities to submit electronic copies of required performance test reports to EPA's WebFIRE database through an electronic emissions test report structure called the Electronic Reporting Tool (ERT). The ERT generates an electronic report which would be submitted using the Compliance and Emissions Data Reporting Interface (CEDRI). The submitted report will be transmitted through EPA's Central Data Exchange (CDX) network for storage in the WebFIRE database making submittal of data very straightforward and easy. The requirement to submit performance test data electronically to EPA applies only to those performance tests conducted using test methods that are supported by the ERT.

D. What are the effective and compliance dates for the Steel Pickling source category amendments?

The effective and compliance date for the final rule amendments is September 19, 2012.

IV. Summary of Significant Comments and Responses

A. Comments and Responses Associated With the Chromium Electroplating and Chromium Anodizing Source Categories

Many 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 the *Responses to Comments* (RTC) document which is available in the Docket for this rulemaking, Docket ID No. EPA–HQ–OAR–2010–0600.

1. Technology Review

Comment: One commenter stated that EPA made the decision to consider more stringent emissions limits primarily because the revised data set indicated that most facilities were operating well below the current emissions limit. The commenter explained that the fact that some facilities operate below the existing standard does not warrant the establishment of revised standards under section 112(d)(6). The commenter added that EPA should expect that some facilities will decide to reduce emissions below the existing standard in order to ensure a compliance buffer. The commenter emphasized that EPA should not set the precedent that an industry that operates with a compliance buffer will be subject to ratcheting down of the standards, since that would create a disincentive for industry sectors to reduce their emissions below the existing MACT standards. The commenter also noted that section 112(d)(6) does not allow EPA to change standards simply because portions of the industry are operating below existing standards or because compliance with new limits may not be cost prohibitive.

The same commenter also stated that EPA has not identified any additional ''practices, processes, [or] control technologies'' that were not identified and considered during the development of the original MACT or the 2010 proposed rulemaking that warrant stricter standards. The commenter explained that EPA's technology analysis stopped when the Agency concluded that facilities are achieving better emissions results than the current standard and once EPA reached that conclusion, the Agency turned to creating options for combining existing technologies to achieve those reduced emission results. The commenter stated that EPA used the emission results to drive the identification of possible combinations of existing technologies and that EPA's basis for revising emissions standards under section 112(d)(6) is not appropriate since section 112(d)(6) requires that any changes in the standards be driven by changes in ''practices, processes, [or] control technologies.'' The commenter added that EPA has not based the proposed emission limit reduction on evidence that new technology has been introduced that can be linked to achieving these new limits (i.e., under section 112 (d)(6)), nor is there ongoing residual risk associated with chromium emissions from these source categories that justifies the stricter standards (i.e., under section 112(f)(2)). Therefore, there is neither a legal nor factual basis for the proposed changes.

Response: We believe the language in section 112(d)(6) provides broad authority for EPA to consider the practices, processes and technologies available at the time we are performing our review. We agree that the fact that some facilities are meeting a limit below the level of the current standard is not alone sufficient to justify revising the existing standard. Rather, we evaluate what practices, processes and technologies are available and consider whether they are cost effective and technologically feasible. If a more stringent standard can be met through cost effective and technologically feasible practices, processes or control technologies, we believe it is necessary within the meaning of section 112(d)(6) to revise the existing 112 standard. We also note that, when developing standards, we take into account the uncertainty associated with measuring emissions and we assume that plants operate with a compliance buffer to minimize the likelihood of exceeding the standard.

Regarding the issue that EPA has not identified any additional ''practices, processes, [or] control technologies'' that were not identified and considered during the development of the NESHAP, the commenter's interpretation of section 112(d)(6) is too narrow. In the 112(d)(6) review, we are not limited to reviewing practices, processes or control technologies that the Agency has never considered. Rather, section 112(d)(6) requires us to take into account developments in practices, processes and control technologies, which include not only new practices, processes and control technologies, but also improvements in efficiency, reduced costs or other changes that indicate that a previously considered option for reducing emissions may now be cost effective or technologically feasible. We also reiterate that improvements in control technology performance over time can provide the basis for revising standards under section 112(d)(6). As explained in the supplemental proposal, many existing facilities have emissions levels more than 10 times below the current emissions limits.

Comment: One commenter stated that EPA is legally required by section 112(d) to set standards based on the best performing sources in California. The commenter stated that current practices and technologies used by the industry in California to comply with rules set by the California Air Resources Board (CARB), 17 Cal. Code Regs. §§ 93101–93102.16, and the South Coast Air Quality Management District (SCAQMD), Rule 1469, represent the type of significant developments that make an update necessary. The commenter pointed out that California standards have achieved greater emission reductions than EPA's existing standard and that EPA may not completely ignore the best-performing similar sources when deciding what limit to set under section 112(d). The commenter listed some of California's standards and stated they are more stringent because they require greater protection for facilities located nearest to sensitive receptors, such as people who attend, work at, or visit schools and daycare centers. In addition, certain facilities are required to use add-on controls, and they require HEPA filters for new sources. The commenter noted that CARB rules limit hexavalent chromium directly, instead of setting limits on total chromium, as under EPA's proposed rule. The commenter stated that EPA should require additional protective measures including siting, monitoring (including continuous emission monitoring), inspection and compliance, public reporting of emissions, community outreach near these facilities to protect public health, systems for community reporting of suspected emission exceedances, enforcement, an 8-year deadline to review and revisit its residual risk analysis for this source category, and similar requirements. For the provisions that require funding, EPA should either allocate or seek this funding, or require registration of each of the chromium electroplating facilities and set a fee for this registration that will pay for these activities. The commenter stated that EPA has not analyzed the ways in which these rules are stronger or provided any discussion of this in the record, as it must do to consider all developments under section 112(d)(6). The commenter stated that EPA has failed to provide any explanation for not considering the California reductions as a regulatory option or explain why EPA's proposed level of the standards for each subcategory is appropriate. The commenter added that California's standards undermine EPA's determination that the existing standards provide an ample margin of safety. Once California demonstrated that it is feasible to require much more

stringent standards than are currently required by the NESHAP, EPA must provide a rational explanation as to why it should not require at least the same level of protection. The fact that California has required HEPA filters for the vast majority of these facilities, while also requiring specific fume suppressants for the smallest facilities, belies EPA's conclusion that its existing MACT meets the test for an ample margin of safety.

Response: We proposed that the existing standards reduce risk to an acceptable level based on our review of health factors such as the maximum individual risk and the number of persons exposed to a cancer risk greater than 1-in-1 million. As part of our technology review and our ample margin of safety analyses, we considered the requirements of California's Airborne Toxic Control Measure (ATCM) for Chromium Plating and Chromic Acid Anodizing Facilities (title 17, California Code of Regulations sections 93102.1 to 93102.16) and of the South Coast Air Quality Management District (SC AQMD) (Rule 1469, Hexavalent Chromium Emissions from Chromium Electroplating and Chromic Acid Anodizing Operations). Specifically, as part of our October 2010 proposal, we evaluated requiring all facilities to install HEPA filters and requiring all facilities that use less efficient controls, such as packed bed scrubbers, to install CMP systems (75 FR at 65092–94); See *Emissions Reductions and Cost Effectiveness of HEPA Filter Retrofits for Chromium Electroplating, and Emissions Reductions and Cost Effectiveness of Composite Mesh Pads for Chromium Electroplating,* which are available in the docket for this rulemaking. These devices, alone or in combination with fume suppressants or other add-on devices, are the controls used to comply with the standards in California. As explained in the 2010 proposal (75 FR 65068) we evaluated the capital costs, annualized costs, cost-effectiveness, and number of plants impacted. Based on those analyses, we concluded that requiring these controls throughout the industry was not appropriate under either section 112(d)(6) or 112(f)(2).

Furthermore, we disagree with the comment that EPA should follow the California example for people who attend or visit schools and daycare centers, or other sensitive receptors that are located close to these sources. Based on our analyses, we conclude that this NESHAP, with the changes being promulgated today, will provide an ample margin of safety for all populations and subpopulations regardless of the location of sensitive receptors and therefore we disagree that a special provision is needed with regard to location of these receptors. With regard to siting requirements, community reporting, community outreach and registration fees, we believe these items are not appropriate or necessary for this National rulemaking.

With regard to the comment that CARB rules limit hexavalent chromium directly (instead of setting limits on total chromium), we believe it is appropriate to regulate chromium compounds (rather than hexavalent chromium) under the national standards developed pursuant to the CAA because section 112(b) of the CAA lists chromium compounds as the HAP which the EPA is to regulate. Nevertheless, because the emissions of total chromium are estimated to be 98 percent hexavalent chromium, a total chromium emissions limit is effectively a hexavalent chromium limit for these source categories. The NESHAP established emission limits in terms of total chromium, as measured by Methods 306 or 306A. Both of these methods measure the total amount of chromium present in the exhaust stream, regardless of the form of the emissions (hexavalent or trivalent chromium).

Comment: A commenter claimed that EPA may not lawfully set surface tension limits as an alternative to an emission standard because doing so violates section 112(h), 42 U.S.C. § 7412(h). The commenter pointed out that section 112(h) of the Act, id. § 7412(h), requires EPA to set a numerical standard for control of HAPs whenever it is feasible to promulgate and enforce a standard in such terms. The commenter acknowledged that EPA may promulgate work practice standards instead of numerical standards only if measuring emission levels is technologically or economically impracticable and that EPA may substitute work practice standards for emission limits only if doing so is consistent with the provisions of subsection (d) or (f). The commenter stated that EPA has not satisfied section 112(h)(1), which is required to set an alternative work practice standard in lieu of an emission standard and added that EPA may not set a section 112(d) emission standard based solely on one type of technology (fume suppressants), when other methods are available to achieve greater reductions. The commenter also said that EPA must set surface tension limits not as an alternative, but in addition to the concentration-based limits. The emission concentration-based limits must apply at all times. The commenter suggested that EPA update and strengthen the proposed surface tension limits so that they are at least as stringent as the emission concentration-based standards, and to require these limits to apply in addition to, but not in lieu of, emission limits.

Response: We disagree with the commenter that it is unlawful to set an alternative to a numerical emissions limit. The CAA allows us to establish alternatives to numerical emissions limits if we can demonstrate that the alternative limit (in this case, the surface tension limit) is at least as stringent as the numerical emissions limit. For the reasons described below, we also reject the commenter's assertion that the proposed surface tension limits are not as stringent as the proposed emission limits. Our analysis shows that maintaining the surface tension at the proposed levels is at least as stringent as the proposed emission limits, both for existing and for new sources. The data demonstrate that, when surface tension is no greater than 40 dynes/cm (when measured using a stalagmometer) or 33 dynes/cm (when measured using a tensiometer), emissions will be no greater than 0.006 mg/dscm. The proposed chromium emission limits for existing sources (0.011 mg/dscm for large hard chromium electroplating, 0.015 mg/dscm for small hard chromium electroplating, and 0.007 mg/dscm for decorative chromium electroplating and chromium anodizing), all exceed the 0.006 mg/dscm concentration associated with the proposed surface tension limits and the emissions limit for all new sources (0.006 mg/dscm) is equivalent to the level achieved with these surface tension limits. We also disagree that the proposed surface tension limits constitute establishing an emission standard based solely on one type of technology (i.e., fume suppressants). The NESHAP sets numerical emission standards for all of the affected chromium electroplating and anodizing sources. However, plants can elect to comply with the standard by meeting the surface tension limits through the use of fume suppressants. Section 112(h)(1) addresses setting an alternative work practice standard when a numerical emission standard is not feasible, but that is not the case for the chromium electroplating NESHAP because the existing NESHAP includes both a numerical emission limit and an alternative surface tension limit that will ensure that the emission limit is met at all times by sources that choose

to use the surface tension limit compliance alternative.

Comment: One commenter stated that EPA reviewed data from only 17 decorative chromium facilities and one anodizing facility, and concluded that all decorative and anodizing facilities already comply with the new proposed emissions limits (77 FR at 6642–6644.) The commenter goes on to say that EPA acknowledged that 8 decorative facilities may need to make adjustments and achieve reductions to meet the new emissions limits, but dismissed these data by claiming that these facilities would choose to comply with the new NESHAP with the surface tension levels rather than the new emissions limits. The commenter noted that EPA admitted that it did not perform any detailed analysis for anodizing facilities. Rather, EPA concluded that anodizing processes are similar enough to decorative processes so the proposed limits would also be appropriate. The commenter stated that EPA had limited data and had weak scientific and technical basis to support or justify the proposed limits for decorative and anodizing facilities.

Response: In evaluating the impacts of the proposed requirements on the existing decorative chromium electroplating and chromium anodizing facilities that comply with emissions limits (as opposed to those plants that comply with the surface tension limits), we reviewed the available data. For the 17 decorative tanks in our data set, all of these tanks have emissions below 0.007 mg/dscm and many have emissions more than 10 times below this level. Although all of the emissions data indicated that existing facilities would meet the more stringent emissions limit of 0.007 mg/dscm, we conservatively assumed that at least some facilities would not meet this limit and would require further controls. The commenter is not correct that we assumed the 8 facilities would choose to comply with the surface tension levels rather than the new emissions limits. However, we did assume those facilities would choose to use fume suppressants to achieve some emissions reductions to comply with the more stringent emissions limits, but we disagree that this assumption means that we dismissed those plants. Using fume suppressant in combination with add-on controls is a relatively common practice for meeting emissions limits in the chromium electroplating industry.

Regarding the data on chromium anodizing, we have obtained emission test data for two additional chromium anodizing plants, one of which is located in Connecticut that reported emissions as 0.0007 mg/dscm, and the other located in Massachusetts that reported a concentration of 0.001 mg/dscm. In addition, we reviewed emission test data we had previously received for three chromium anodizing plants located in California. The data show emissions for tanks controlled with HEPA filters to range from 0.0000097 to 0.00056 mg/dscm. Based on the control efficiencies reported by California, we estimate that, if these tanks were controlled with CMPs instead of HEPA filters, emissions would range from 0.000097 to 0.0056 mg/dscm. As shown in the cost analysis technical memo, we already had data for a plant in Oklahoma with reported emissions of 0.0016 mg/dscm.

With regard to add-on controls, based on available information we conclude that the CMP is a readily available control technology that can be applied to anodizing plants and can easily meet a limit of 0.007 mg/dscm for these type of plants. Other technologies can also likely meet this limit. For example, the Connecticut and Massachusetts plants have chromium mist eliminators (and have emissions of 0.0007 mg/dscm, and 0.001 mg/dscm, respectively) and the plant from Oklahoma, which has emissions of 0.0016 mg/dscm, is controlled with a wet scrubber. The data from the Connecticut plant, Massachusetts plant, Oklahoma plant, and the plants in California all support our assumption that most existing chromium anodizing plants that are currently complying with the existing emission limit could easily meet the revised emissions limit of 0.007 mg/dscm without additional controls. We received no data for any decorative or anodizing plants that would not be able to meet these lower limits.

2. Risk Assessment

Comment: One commenter contended that EPA did not assess multipathway health risk for chrome plating because hexavalent chromium is not on the outdated list of 14 PB–HAPs that EPA has used for this risk assessment. The commenter noted EPA's statement that, "PB–HAP emissions were not identified from the chromium anodizing, decorative chromium electroplating, and hard chromium electroplating source categories, indicating that exposures due to non-inhalation routes of exposure are not significant." The commenter argued that this is unlawful, arbitrary and capricious because the science demonstrates this pollutant can indeed cause health effects when a person is exposed through a pathway other than inhalation. Evolving research continues to show risk to animals and thus, potentially, both to the environment and to human health, from oral and systemic exposure through water-based ingestion, rather than just inhalation. EPA therefore must assess the multipathway health risk.

The commenter supported this argument by referring to California EPA's Office of Health Hazard Assessment (OEHHA)'s recent revisions to Risk Assessment Guidelines, which, according to the commenter, provide evidence that under some environmental conditions hexavalent chromium contamination can persist in soil presenting an exposure risk via ingestion and dermal exposure to contaminated soils, creating a cancer risk.[1] The commenter noted that EPA's failure to consider cancer risk from ingestion in its analysis is unlawful, arbitrary and capricious.

The commenter recommended that the EPA perform a multipathway analysis for this source category that fully accounts for exposure that can occur to a child in an urban or residential setting. The commenter suggested that the EPA assess multipathway risk based on the allowable emissions, as it has done for inhalation risk. Further, the commenter reported that the OEHHA's scientists found that there is the potential for hexavalent chromium uptake in plants and fish and concluded that to protect public health, exposure via ingestion of contaminated crops and fish must also be considered.

Response: The current persistent and bioaccumulative HAP (PB–HAP) list in the Air Toxics Assessment Library (see *http://www.epa.gov/ttn/fera/risk_atra_main.html*), was developed considering all of the available information on persistence and bioaccumulation. This list was peer-reviewed by the SAB, and it is reasonable to use it in the RTR program. In addition, the Agency does not have information, nor did the commenter provide information, that would enable the EPA to determine whether the deposition of airborne hexavalent chromium from chromium electroplaters and the subsequent movement of the hexavalent chromium in the environment would result in human exposures that could be of concern. With regard to the environment, the limited available

[1] Cal. EPA, OEHHA, Air Toxics Hot Spots Program Risk Assessment Guidelines, Technical Support, Document for Exposure Assessment and Stochastic Analysis, Scientific Review Panel Draft at F–27, E–5 (Feb. 2012), *http://oehha.ca.gov/air/hot_spots/SRP/index.html*), *http://oehha.ca.gov/air/hot_spots/SRP/index.html;* see also id. at E–12 tbl. E3 (describing exposure pathways for analysis).

information on the persistence and bioaccumulation of hexavalent chromium suggests that there is no indication of the biomagnifications of hexavalent chromium along the aquatic food chain, and that chromium has low mobility for translocation from roots to aboveground parts of plants. (ATSDRs Tox profile 2008 *http://www.atsdr.cdc.gov/toxprofiles/tp7.pdf*).

Comment: One commenter stated that the residual risk assessment underestimates risk to the developing child and fetus. The commenter observed that biological differences in the developing child and fetus can result in increased cancer and non-cancer risk due to both increased exposure and increased vulnerability, and emphasizes that the EPA must account for the increased susceptibility of children to HAP emissions from this source category in the risk assessment. The commenter noted that according to OEHHA, there is an increased risk indicated from early life exposures and asserted that EPA's failure to include an adequate evaluation of increased early life susceptibility to HAP emissions systematically underestimates risk from hexavalent chromium emissions of this source category. The commenter stated that the EPA must follow the lead of OEHHA and include additional factors to address early life exposure in its risk assessment. The commenter also cited a recent EPA toxicological review and cancer toxicity reviews from California EPA (CalEPA) that provide evidence for the mutagenic activity of hexavalent chromium compounds, and developmental, female reproductive and male reproductive toxicity.[2 3 4] The commenter suggested that under the 2005 Guidance, risk assessments of exposure to hexavalent chromium should include adjustment for early life exposures and the estimates included in the residual risk assessment fail to include the full health risk.

The commenter noted that the EPA restricted its application of age-dependent adjustment factors to those HAPs included in EPA's 2006 list of carcinogenic HAPs that act by a mutagenic mode of action, and did not apply age-dependent adjustment factors to assess cancer risk from chromium. The commenter recommended that the EPA update both its 2005 *Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens* (attached to comment letter), and EPA's 2006 list of carcinogenic HAPs that act by a mutagenic mode of action to use age-dependent adjustment factors for hexavalent chromium in the *Supplemental Guidance* and incorporate more recent evaluations of carcinogenic modes of action in the list of carcinogenic HAPs. The commenter also suggested that the EPA should consult with multiple scientific bodies on the scientific basis of the proposed rulemaking: National Academy of Sciences, the Office of Children's Health Protection, the Children's Health Protection Advisory Committee, and scientists in the Office of Research and Development who focus on children's and community health (such as experts in the National Center for Environmental Research). The commenter asked the EPA to consider and follow its 2008 handbook on child-specific exposure factors in this rulemaking, and follow the Science Advisory Board's recommendations regarding the greater exposure and vulnerability of children.[5]

The commenter also pointed out that Congress recognized this science in the Food Quality Protection Act (FQPA) for pesticide chemical residue, where Congress used a ten-fold margin of safety for infants and children. The commenter also provided a table of comparisons between OEHHA child-health reference values and those of EPA.

Response: The EPA disagrees with the commenter's statement that the risk assessment underestimates risk to children and lacks consideration of early-life susceptibility. The EPA agrees that biological differences across lifestages may lead to differences in the susceptibility to HAP, as can differences among population groups due to pre-existing disease states or other factors. Accordingly, the methods we use in risk assessments have taken this into account. For the dose-response component of HAP assessments for RTR, the EPA uses exposure reference concentrations and unit risk estimates (UREs) that are expressly derived with the objective of protecting sensitive populations and lifestages, including children (see U.S. EPA, 2002). A Review of the Reference Dose and Reference Concentration Processes. EPA/630/P–02/002F. Risk Assessment Forum, Washington DC. Available online at *http://www.epa.gov/raf/publications/pdfs/rfd-final.pdf*). For example, a review of the chronic reference value process concluded that the Agency's reference concentration (RfC) derivation process adequately considers potential susceptibility of different subgroups with specific consideration of children, such that the resultant RfC values pertain to the full human population including "sensitive subgroups," inclusive of childhood. With respect to cancer risk assessments, assessments are performed in accordance with EPA's Supplemental Guidance for Assessing Susceptibility from Early-life Exposure to Carcinogens (US EPA, 2005). This Guidance recommends the application of age-dependent adjustment factors for assessing cancer risk from carcinogenic pollutants concluded to act via a mutagenic mode of action and for which information on early-life susceptibility is lacking. The basis for this methodology is provided in the 2005 Supplemental Guidance. With regard to other carcinogenic pollutants for which early-life susceptibility data are lacking, it is the Agency's long-standing science policy position that use of the linear low-dose extrapolation approach (without further adjustment) provides adequate public health conservatism in the absence of chemical-specific data indicating differential early-life susceptibility or when the mode of action is not mutagenicity (U.S. EPA, 2005).[6]

EPA disagrees with the commenter that EPA should use California EPA's child-specific reference doses for school site risk assessments[7] in order to address the potential for early-life susceptibility. EPA methods for assessing hazard and dose-response relationships for HAPs and developing RfCs and cancer risk estimates, as noted above, specifically address the potential for early-life susceptibility. Whenever data indicate increased susceptibility of a developmental lifestage or of a population group, those data are

[2] EPA, IRIS, Draft, Technological Review of Hexavalent Chromium (CAS No. 18540–29–9), In Support of Summary Information on the Integrated Risk Information System at 238 (Sept. 2010).

[3] Cal. EPA OEHHA, Public Health Goal for Hexavalent Chromium in Drinking Water (July 2011).

[4] Cal. EPA, OEHHA, Evidence of the Developmental and Reproductive Toxicity of Chromium (Hexavalent Compounds) 3 (Aug. 2009), *http://www.oehha.ca.gov/prop65/hazard_ident/pdf_zip/chrome0908.pdf*.

[5] U.S. EPA, Child-Specific Exposure Factors Handbook (Sept. 2008), EPA/600/R–06/096F, *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=199243*.

[6] The EPA has not yet determined whether hexavalent chromium poses disproportionate risks to children, but is currently developing an assessment of hexavalent chromium which likely will address that issue.

[7] We note that California EPA's use of these numerical values, which do not exist for inhalation exposures, is limited to the context of risk assessment at proposed or existing California school sites and does not extend to their Air Hot Spots Risk Assessment program. Further the guidance for the California EPA school site assessment program specifies the use of California OEHHA or U.S. EPA IRIS values in the absence of the school site risk assessment child-specific values (Cal OEHHA, 2004—*http://www.oehha.ca.gov/public_info/public/kids/pdf/SchoolscreenFinal.pdf*).

factored into the analysis. When data are inadequate to understand the effects of a specific pollutant on sensitive subpopulations, which, for some pollutants, may include children, the Agency's risk assessment methods take that into account to ensure that resulting assessments address the possibility that such subpopulations might be more or less sensitive.

3. Environmental Justice

Comment: One commenter questioned why EPA's risk assessment did not consider all of the factors recommended in EPA's own Environmental Justice Strategic Enforcement Assessment Tool (EJSEAT) and why EPA did not propose stricter controls in light of the demographic risk results for hard chromium electroplaters. The commenter also stated that, as specified in the EPA's Interim Guidance on Considering Environmental Justice during the Development of an Action, EPA should consider addressing existing disproportionate impacts on minority, low-income or indigenous populations during this rulemaking. The commenter requested that a full evaluation of disproportionate impacts be conducted following guidance in EJSEAT and an evaluation of how this assessment could reduce impacts to those communities. The commenter noted that the Online Tracking Information System (OTIS) database appears to do this already at the facility-specific level and can be incorporated into the assessment to more accurately define the number of the individuals impacted by the emissions and the demographics of the impacted community. The commenter recommended that EPA work with the Office of Environmental Justice to adequately evaluate the proposed rulemaking with regard to communities experiencing disproportionate impacts.

Another commenter stated that CARB has created a draft methodology to screen for cumulative impacts in communities. EPA should use this or a similar tool to find and provide greater protection for the local communities most affected by this source category. EPA has even developed a draft version of this type of tool for enforcement and compliance purposes, specifically the EJSEAT that, without explanation, it has not used in this rulemaking.

Response: The EPA's "Interim Guidance on Considering Environmental Justice During the Development of an Action," encourages rule writers and policy makers to look at the whole range of relevant factors that impact communities and population groups when crafting rules. The EPA is continuing to discuss and pilot approaches for conducting its analyses that are consistent with the agency's responsibilities regarding EJ as outlined in Executive Order (EO) 12898.

We believe these NESHAP, with the amendments being promulgated in today's action, will provide an ample margin of safety to protect the health of all population groups. As stated in the Benzene NESHAP, in determining the need for residual risk standards, we strive to limit to no higher than approximately 1-in-10 thousand (100-in-1 million) the estimated cancer risk that a person living near a plant would have if he or she were exposed to the maximum pollutant concentrations for 70 years and, in the ample of safety decision, to protect the greatest number of persons possible to an individual lifetime risk level of no higher than approximately 1-in-1 million. These considerations are made for all people regardless of racial or socioeconomic status. However, in determining whether to require additional standards under Section 112(f), these levels are not considered rigid lines, and we weigh the cancer risk values with a series of other health measures and factors in both the decision regarding risk acceptability and in the ample margin of safety determination. We also consider cost of controls in the ample margin of safety determination.

The results of our demographic analyses for hard and decorative chromium electroplating indicate that certain minority groups and low-income populations may be disproportionately exposed to emissions from these categories and to any risks that may result due to these emissions because the communities most proximate to facilities within these categories have a higher proportion of these groups than the national demographic profile. We did not identify any vulnerability or susceptibility to risks particular to minority and low income populations from pollutants emitted from this source category. The Agency has determined that the existing NESHAP for these source categories reduce risk to an acceptable level for all proximate populations, including minority and low-income populations.

We agree with the commenter on the importance of working closely with the EPA's Office of Environmental Justice (OEJ), as well as other offices across the agency, to develop criteria and specific guidance on how to interpret and apply the outcome of our analyses in the rulemaking process. While the EJSEAT and OTIS database are general tools that can be used in considering environmental justice issues, the demographic analyses we performed are more appropriate for this source category-specific rulemaking. We are working with the OEJ, the Office of Research and Development and other Agency offices in an ongoing effort to assess ways to address cumulative risk and develop new tools for considering environmental justice in rulemakings.

In addition, as addressed more fully in the RTC, while we understand that some communities are exposed to multiple pollutants emitted by many different types of sources, EPA under Plan 2014 is assessing ways to address these exposures through a cumulative impact analysis.

4. Emissions Estimates

Comment: In response to the 2012 supplemental proposal, one commenter contacted approximately 300 of the facilities that EPA identified as having the highest emissions and received information from 181 plants. The commenter stated that out of the plants that responded, 62 plants were closed, 24 plants do not use chromium, 39 plants have lower emissions than reported by EPA, and 7 plants have emissions estimates consistent with that relied on by EPA. The commenter also claimed the data for several other plants were incorrect. If revisions were made to emissions estimates for these 181 plants based on this information, the resulting overall emissions would be 73% lower than the EPA's estimates for these 181 plants. The commenter recognized that estimates found for the higher-emitting, higher-risk facilities could in part be counterbalanced by emissions estimates for lower risk facilities the commenter did not investigate, but the commenter believes that EPA's analysis would still not account for the 73% reduction in emissions for this set of facilities resulting from facility closures and switches to non-hexavalent chromium processes.

Response: We reviewed the data provided by the commenter and we created a separate source category emissions dataset that reflects most of the changes suggested by the commenter. Specifically, we excluded all plants reported by the commenter to be closed or to not use hexavalent chromium. We also included revised emissions estimates for several plants. We conducted risk modeling with this dataset, and the results were not significantly different from the assessment conducted for the supplemental proposal. The MIR, HI, and incidence estimates for all source categories were essentially unchanged, and the population risk differences were

not significantly different. For example, for the hard chromium electroplating source category, the number of people estimated to be at cancer risk greater than or equal to 1-in-1 million is 120,000 based on the new dataset, and 130,000 in the previous assessment. Because of the very small differences in risk results based on this modeling, we decided that the data do not warrant revising the overall risk assessment we conducted for the supplemental proposed rule. Regardless, the data do not change the decisions set forth in the supplemental proposal.

5. Costs and Economic Impacts of Proposed Limits

Comment: One commenter believes that EPA has under-estimated the costs associated with using non-PFOS fume suppressants and questions whether EPA evaluated comparable products when coming up with costs for fume suppressants. The commenter noted that fume suppressants are available in a number of different formulations that contain non-PFOS and PFOS in various concentrations. The commenter stated that EPA has not included all of the additional costs associated with the use of non-PFOS fume suppressants, such as the differences in the frequency that suppressants need to be added to plating baths, and the increased surface tension monitoring and maintenance associated with use of non-PFOS fume suppressants. The commenter further explained that several facilities have reported that costs for converting to non-PFOS fume suppressant may be more than 30 percent higher than using PFOS fume suppressants. The commenter stated that one facility estimated that its annual costs for fume suppressants would increase by approximately $100,000 with the switch to non-PFOS fume suppressants.

Response: To support the supplemental proposal, EPA contacted several fume suppressant vendors in order to calculate the costs of both PFOS and non-PFOS based fume suppressants. After reviewing the information from vendors, we concluded costs for the non-FOS suppressants would be similar to the costs for PFOS suppressants or slightly higher. To be conservative (more likely to overestimate rather than underestimate the costs), we estimated that the cost of non-PFOS fume suppressants was 15% higher than that of PFOS fume suppressants (see *Procedures for Determining Control Costs and Cost Effectiveness for Chromium Electroplating Supplemental Proposal* memorandum, which is available in the docket for this action). After receiving comment on the supplemental proposal, EPA contacted several facilities in Minnesota that have switched from a PFOS-based fume suppressant to a non-PFOS-based fume suppressant and asked for information on the price differences between the two products. Three facilities contacted agreed that the price of non-PFOS was slightly higher, but were not aware of how much higher, while three other facilities stated they did not consider the products to have a significant difference in price. Additionally, EPA asked facilities about any changes in fume suppressant consumption that may have occurred after switching to a non-PFOS fume suppressant. One facility stated that they consume less fume suppressant after switching to a non-PFOS fume suppressant and therefore overall costs were similar or perhaps have decreased since switching to the non-PFOS suppressant. All other facilities stated they did not notice any difference in effectiveness, consumption, or required maintenance of the non-PFOS fume suppressant (see *Information on non-PFOS Fume Suppressants in Minnesota Chromium Electroplating Facilities* memorandum, which is available in the docket for this action). While the commenters raise general concerns about potential higher costs, they did not provide any specific details about why costs would be higher for any specific facility or group of facilities. Based on the best information available to us, we believe that the price and cost methodology we are relying on for this rule provide reasonable estimates of the costs associated with using non-PFOS fume suppressants.

6. Non-PFOS Fume Suppressants

Comment: Two commenters stated that EPA has not demonstrated that the proposed surface tension limits can be met using non-PFOS fume suppressants. One commenter pointed out that the data used by EPA to support the proposed surface tension limits are based on chromium electroplating tanks controlled with WAFS that contain PFOS. The commenter recognized that EPA proposed a 3-year compliance date for the limit on the use of WAFS containing PFOS. The commenter believes that EPA has not demonstrated that the proposed surface tension limits can be met using non-PFOS WAFS.

One commenter stated that EPA has provided no data in the record that shows non-PFOS fume suppressants can achieve the proposed new surface tension levels and that EPA merely assumes non-PFOS fume suppressants are equivalent in performance to PFOS fume suppressants without presenting any scientific proof or supporting data. The commenter believes that EPA ignored the fact that fume suppressants can perform differently in decorative chromium and chromium anodizing plating baths. The commenter explained that the data that EPA references to support its claim that fume suppressants effectively reduce emissions to meet the proposed limits is flawed and provides no scientific evidence that fume suppressants can be used to achieve the proposed emissions limits. The commenter added that EPA cannot claim, in the absence of any credible data in the record, that non-PFOS fume suppressants can reduce emissions as effectively as PFOS fume suppressants. Due to the challenges facing chromium electroplating and anodizing operations in using the new technology to meet the current surface tension levels and the lack of any data in the record to demonstrate that non-PFOS fume suppressants can consistently achieve the proposed surface tension levels, the commenter recommended EPA forego the proposed revisions to the surface tension levels. The commenter also suggested that the burdens of the proposed changes clearly outweigh any perceived benefits. The commenter believes PFOS is a very effective fume suppressant because of its persistent and bio-accumulative nature and acknowledged that PFOS and other long-chain perfluorinated compounds (PFCs) are being phased out by EPA and by other regulatory agencies globally because of the environmental impacts that may result from the use of PFOS. The commenter, however, feels that the biggest challenge in meeting the revised surface tension levels stems from the phase-out of PFOS. The commenter stated that facilities that have switched to non-PFOS fume suppressants have achieved moderate success in meeting the current surface tension levels, but many challenges and problems persist. The commenter believes the switch to non-PFOS fume suppressants diminishes a facility's margin of compliance in meeting the current surface tension levels. The commenter goes on to say that where non-PFOS has shown promise in lowering surface tension levels, it requires more frequent additions, more frequent monitoring, and more labor to maintain surface tension levels compared to the use of PFOS fume suppressants.

Response: Fume suppressants are used to lower the surface tension of electroplating baths, which in turn, reduces the size of gas bubbles generated during electrolysis. These smaller bubbles travel more slowly

through the solution and have less energy when they arrive at the solution's surface. The lower surface tension also reduces the energy with which the resulting droplets are ejected into the air. Together, both of these effects can reduce the emission of droplets, which in turn reduces the amount of chromium emitted by the tank. It is our understanding that this relationship between surface tension and chromium emissions is dependent primarily on the surface tension of the tank and not on the product used to reduce surface tension.

We acknowledge that there may be differences in the performance of non-PFOS based fume suppressants in different types of chromium electroplating tanks, but this is also true of PFOS based fume suppressants. The performance of any type of fume suppressant can depend on the characteristics of the chemical and tank (i.e., temperature, contaminants present, etc.), but EPA has found no evidence that supports the idea that non-PFOS based fume suppressants are unable to reach the surface tension limits being finalized in this rulemaking. EPA contacted several fume suppressant vendors to request information on non-PFOS fume suppressants. The vendors who responded were confident that their non-PFOS fume suppressants could reach the proposed surface tension limits (see *Information on Non-PFOS Fume Suppressants for Chromium Electroplating Supplemental Proposal* memorandum). It has been reported that there are now suitable, successful and well proven non-PFOS fume suppressants for hard and decorative chromium electroplating, and that the surface tension can be reduced to as low as 20 dynes/cm in baths, but are commonly maintained at about 30 dynes/cm. At this level, consumption of the suppressant is minimized and emissions are controlled (Barlowe, G. and Patton, N., 2011). For example, surface tension data from one decorative chromium electroplating plant in Minnesota that has been using non-PFOS fume suppressant for years show they had an average surface tension of 28.7 dynes/cm over the first 6 months of 2012, and their highest reading was 32.4 dynes/cm. They had several readings below 23 dynes/cm, and some values were as low as 18.5 dynes/cm. These data indicate that 33 dynes/cm is quite feasible, especially for decorative chromium electroplating sources. Furthermore, a study by the Danish EPA (Danish EPA, 2011) found that the non-PFOS fume suppressant reduced emissions just as effectively as the PFOS for about the same costs.[8]

In a separate meeting, the EPA discussed the effectiveness of non-PFOS fume suppressants with a major distributer of both PFOS and non-PFOS fume suppressant. The distributor discussed issues that arise when using any type of fume suppressant and stated that, worldwide, they have experienced issues with the switch to non-PFOS based fume suppressants with only a couple of companies. The distributor was confident that their non-PFOS based products could reach the proposed limits and noted that the phase-out of PFOS fume suppressants in Europe and Japan occurred seamlessly (See Summary of EPA Meeting with Atotech March 1, 2012, in the docket for this rulemaking).

EPA also contacted several facilities in Minnesota that have switched from a PFOS-based fume suppressant to a non-PFOS fume suppressant and asked them to describe any changes in the effectiveness or consumption of the fume suppressant. All facilities stated that the non-PFOS based fume suppressant was equally effective as the PFOS-based fume suppressant, with one facility noting the non-PFOS based fume suppressant performed more effectively. In terms of consumption, all facilities stated they have not noticed any increase in fume suppressant consumption since the switch, with one facility stating they consume less fume suppressant per operating hour since switching to the non-PFOS fume suppressant. The facilities that responded also reported no issues with maintaining surface tension levels consistent with the limits we are establishing in the final rule, with one facility stating that since the switch they have seen less surface tension fluctuations in their tank. The responses of Minnesota facilities are summarized in the *Information on Non-PFOS Fume Suppressant Use at Minnesota Chromium Electroplating Facilities* memorandum located in the docket of this rulemaking. Also industry representatives submitted comments supporting the PFOS phase-out.

Comment: One commenter stated that the phase-out of PFOS is being proposed without adequate study of the non-PFOS materials ability to perform as well as PFOS and meet the proposed lower emission limits (as measured by surface tension). The commenter indicated that neither the 2010 proposal docket nor the docket for the supplemental proposal included the reference materials needed to substantiate EPA's conclusions on the availability and feasibility of using non-PFOS fume suppressants to meet the proposed surface tension or emission limits. The commenter is also concerned with the lack of information on how these alternate materials may affect the parts being plated and noted that the procedures followed for their aircraft maintenance are very tightly controlled with extensive testing done prior to implementation of any new procedures. The commenter stated that until adequate testing is completed, which can take longer than the proposed three year timetable for the PFOS phase-out, they will be unable to change to an alternate fume suppressant. The commenter recommended additional study of the available alternatives for aeronautics plating and a process by which industry may petition for additional time to complete the transition to non-PFOS fume suppressants.

Response: EPA has included several documents on the performance of non-PFOS based fume suppressants in the docket to this rule-making (see previous responses). EPA agrees that some electroplaters of highly specialized products may need to perform additional testing in order to integrate the use of non-PFOS fume suppressants and that this testing may require a longer time commitment compared to other products. Nevertheless, we believe that this testing can be accomplished by the compliance date, which is 3 years after the date of publication of this **Federal Register** notice. Additionally, the Clean Air Act allows facilities to apply for an extra year if needed for compliance. Therefore, facilities could have up to 4 years to comply, which should be adequate time to resolve any remaining issues associated with the switch to non-PFOS suppressants.

B. Comments and Responses Associated With the Steel Pickling Source Category

Comment: One commenter opposed the proposed removal of the source-specific alternative concentration standard for chlorine (Cl_2) at HCl acid regeneration facilities. The commenter stated that the current regulation was specifically written to allow for the production of iron oxide of acceptable quality, and that removing the "alternative concentration standard" may have the unintended consequence of reducing the quality of the iron oxide produced and negatively impact the marketability of the material. The commenter noted that there are a

[8] Danish, EPA. 2011. Substitution of PFOS for use in non-decorative hard chrome plating. Pia Brunn Poulsen, Lars K. Gram and Allan Astrup Jensen. Danish Environmental Protection Agency. Environmental Project No. 1371 2011.

number of operational variables, including temperature and excess air, that must be manipulated to produce product to particular specifications. The commenter stated, ''HCl regeneration plants have had to regularly modify and adapt operational parameters such as burner temperatures and nozzle types and pressures in order to meet the changing product specifications of the marketplace. The current regulation accounts for such variability by allowing for the setting of 'alternative concentration standards' due to the impact that such operational adjustments may have on Cl_2 emissions. The existing regulation demonstrates EPA's intent to allow HCl regeneration plants the ability to produce marketable products in changing markets and changing operational conditions. The proposed revision would undermine that intent and remove the operational flexibility that is necessary for HCl regeneration facilities to adapt to changing markets.''

Response: We agree with the commenter to the extent the commenter suggests that the basis for the alternative compliance standard in the original MACT was for the purpose of allowing sources to ''produce iron oxide of acceptable quality.'' However, section 112(d)(2) provides that EPA must establish a standard that ensures the maximum reductions of air pollutants subject to section 112, taking into consideration several factors. For existing sources that standard may not be less than the average emission limit achieved by the best performing 12 percent of existing sources or the average emission limitation achieved by the best performing five sources for which EPA could reasonably obtain information where the source category contains fewer than 30 sources. This is referred to as the MACT floor. Section 112 makes no allowance for establishing a standard less stringent than the floor for sources to which the floor applies. (72 FR 61060). For that reason, we believe that we inappropriately promulgated the alternative compliance limit at the time we promulgated the initial MACT standard. While it is true that the changing operational conditions have an effect on Cl_2 emissions, EPA believes there are available techniques for controlling Cl_2 emissions other than the modification of the operational parameters mentioned by the commenter. EPA believes that both a marketable product can be produced and the Cl_2 emission limit can be met. If a facility is unable to meet the Cl_2 emission limit and produce a marketable product by adjusting their operational parameters, our review and analysis of available information indicate that the emission limit for chlorine can be met using available control technologies such as alkaline scrubbers.

Comment: One commenter noted that while EPA asserts that the source-specific alternative concentration provision does not meet the requirements in section 112(d)(2) and (3) of the CAA because MACT standards for existing sources cannot be less stringent than the average emissions 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), EPA previously promulgated a regulation which allowed an alternative concentration standard. The commenter also stated that the CAA allows EPA the regulatory flexibility to set source-specific concentration standards for particular pollutants.

The commenter also noted that despite recently concluding that no new technology has been developed since the promulgation of the current regulation, and despite no new interpretation of the data supporting the promulgation of the current regulation, EPA has proposed to remove the ''alternative concentration standard'' provision. The commenter claims such a deletion is not merited by the facts nor required by the Clean Air Act, and that the current rule is lawful. The commenter also noted that the existing NESHAP provides an ample margin of safety to protect public health and prevent an adverse environmental effect.

Response: EPA believes that the alternate source specific provision does not meet the requirements in section 112(d)(2) and (3) of the CAA, and the CAA does not allow the regulatory flexibility to set source-specific concentration standards for particular pollutants. We disagree to the extent the commenter is suggesting that because EPA previously promulgated the alternative, it therefore must be consistent with the CAA. Neither the proposed nor final MACT rule provided the legal basis for the alternative and, since that time, the courts have rejected similar provisions in other standards. (72 FR 61060). The commenter cites no specific authority for the statement that the CAA allows EPA to set source-specific concentration standards for particular pollutants.

We also disagree with the commenters statement that in the original MACT rulemaking we concluded that we could set a numerical emission standard for Cl_2 ''so long as there was also the option to set alternative source-specific limits in order to ensure that facilities could actually produce marketable products.'' We drew no such linkage in that rulemaking. We agree with the commenter that we have not identified any new technology to provide further control of chlorine emissions. However, we are not basing this revision on section the 112(d)(6) review of developments in processes and control technologies. Rather, we are making this correction under CAA sections 112(d)(2) & (3) because we believe that the alternative compliance option was improperly promulgated at the time we promulgated the initial MACT standard. Although not relevant to the decision that a less stringent alternative compliance is not appropriate under section 112(d)(2) & (3), we note that the commenter has not claimed that it cannot meet the MACT standard through the use of alkaline scrubbers. The final rule based the standard for chlorine emission control on the use of single stage water scrubbing and the limit of 6 parts per million by volume (ppmv) is based on test data from facilities using that technology. However, if a facility cannot meet the limit using water scrubbing, they still have the option of using an alkaline scrubber to achieve compliance. The EPA stated in 62 FR 49063, ''Wet scrubbing systems that do not use alkaline solution as the collection medium do not effectively control Cl_2 emissions.''

Comment: One commenter stated that, ''EPA must look to the emissions in the industry to determine the MACT floor at the time EPA proposes to amend the rule.'' The commenter also noted that it does not appear that EPA has considered any new data in making the decision to do away with the ''alternative concentration standards.'' The commenter argued that the MACT floor is more than the existing standard of 6 ppmv, and in addition, EPA has the authority under the CAA to account for variability in emissions or operational factors in setting such standards, and cites *Cement Kiln Recycling Coalition* v. *EPA*, 255 F.3d 855 (DC Cir. 2001).

The commenter would like to know how EPA proposes to address such facilities' requests for alternative concentration standards, and how EPA proposes to regulate any facilities with alternative concentration standards.

Response: During the development of the original rule, EPA calculated the MACT floor for existing sources to be 6 ppmv and EPA does not believe the MACT floor would currently be any higher. In this rulemaking, we are not

amending the MACT standard nor re-assessing the MACT floor. Rather, we are removing the provision in the regulation allowing sources to seek a less stringent emission limit than the floor limit. Thus, we do not agree that we need to recalculate the MACT floor. However, we note that the commenter did not provide, and we are not aware of, any information that would indicate that a MACT floor determined 10 years after the original MACT was promulgated would be less stringent, particularly in light of the fact that 3 out of the 5 sources subject to the MACT standard have never indicated that there are compliance issues with that standard. The elimination of the alternative standard from the rule means the rule will no longer allow facilities to request alternative concentration standards.

Comment: One commenter stated that EPA's conclusion that the proposed removal of the "alternative concentration standard" provision will have a capital cost in the range of $100,000 to $200,000, cannot be supported by fact. The commenter also noted that in its description of the proposed revision, EPA states that there is no control technology available that is more effective in removing Cl_2 than existing technology already used by HCl regeneration facilities. The commenter stated that EPA's two statements are irreconcilable; how can a facility spend $100,000 to $200,000 to upgrade control equipment with new technology that does not exist? The commenter would like to know what EPA proposes existing facilities do that already have state of the art control technology.

Response: As noted in previous responses, alkaline scrubbers constitute an existing technology that is effective at controlling Cl_2 emissions. We are not suggesting that facilities upgrade to "new technology" but rather that they convert at least one of their existing water scrubbers to an alkaline scrubber. The cost range presented in the proposed rule represents the estimated capital cost to upgrade a scrubber from using water to using an alkaline solution, if necessary to meet the emission limit. Based on available information, EPA believes sources can achieve the MACT standard with readily available control technologies (e.g., alkaline scrubbers) at reasonable cost and still produce a marketable product.

V. Summary of Cost, Environmental and Economic Impacts

A. What are the affected sources?

1. Chromium Electroplating and Chromium Anodizing

For the amendments to the Chromium Electroplating NESHAP, the affected sources are each hard chromium electroplating tank, each decorative chromium electroplating tank, and each chromium anodizing tank located at a facility that performs hard chromium electroplating, decorative chromium electroplating, or chromium anodizing.

2. Steel Pickling

For the amendments to the Steel Pickling NESHAP, the affected sources are steel pickling and hydrochloric acid regeneration plants that are major sources of HAP.

B. What are the emission reductions?

1. Chromium Electroplating and Chromium Anodizing

Overall, the amendments to the Chromium Electroplating NESHAP will reduce nationwide emissions of chromium compounds by an estimated 224 pounds per year (lbs/yr) from the current levels of 956 lbs/yr down to 732 lbs/yr. For large hard chromium electroplating, the amendments will reduce chromium compound emissions by about 148 lbs/yr from 454 lbs/yr down to 306 pounds. For small hard chromium electroplating, the amendments will reduce chromium compound emissions by an estimated 33 lbs/yr from 223 lbs/yr to 190 lbs/yr. For decorative chromium electroplating, the amendments will reduce chromium compound emissions by an estimated 35 lbs/yr from 222 lbs/yr down to 187 lbs/yr. For chromium anodizing, the amendments will reduce chromium compound emissions by an estimated 8 lbs/yr from 57 lbs/yr down to 49 lbs/yr. The amendments will have negligible impacts on secondary emissions because the additional control equipment that would be required will not significantly impact energy use by the affected facilities.

2. Steel Pickling

We estimate that the amendment to remove the alternative compliance provision for hydrochloric acid regeneration facilities will reduce emissions of chlorine by 15 tpy.

C. What are the cost impacts?

1. Chromium Electroplating and Chromium Anodizing

We estimate that these amendments will achieve 224 pounds reductions in hexavalent chromium emissions, and that the total capital and total annualized cost for these amendments is $8.2 million and $2.4 million, respectively. The overall cost effectiveness is $10,600 per pound of hexavalent chromium emissions reductions. A summary of the estimated costs and reductions of hexavalent chromium emissions are shown in Table 8.

TABLE 8—SUMMARY OF COST IMPACTS FOR CHROMIUM ELECTROPLATING AND ANODIZING ASSOCIATED WITH SURFACE TENSION AND EMISSION LIMIT REQUIREMENTS

Source category or subcategory	Number of affected plants	Capital costs (controls + WAFS + all testing)	Annualized costs (controls + WAFS + all testing), $/yr	Emissions reductions (lbs/yr)	Cost effectiveness (per lb)
Large Hard Chromium Electroplating	57	$6,377,000	$1,686,000	148	$11,400
Small Hard Chromium Electroplating	91	1,424,000	476,000	33	14,600
Decorative Chromium Electroplating	313	163,000	166,000	35	4,800
Chromic Acid Anodizing	74	235,000	51,000	8	6,600
Total	535	8,200,000	2,380,000	224	10,600

Additionally, the total estimated capital and annualized cost for the housekeeping requirements of these amendments is $934,000 and $228,000, respectively.

2. Steel Pickling

For HCl acid regeneration plants, we estimate that the total capital cost for the amendments is between $100,000

and $200,000, depending on whether the existing equipment can be upgraded or will need to be replaced. The annualized costs are estimated to be between $11,419 and $22,837 per year. The estimated cost effectiveness is $761 to $1,522 per ton of HAP (mainly chlorine).

D. What are the economic impacts?

1. Chromium Electroplating and Chromium Anodizing

EPA performed a screening analysis for impacts on affected small entities by comparing compliance costs to average sales revenues by employment size category.[9] This is known as the cost-to-revenue or cost-to-sales ratio, or the ''sales test.'' The ''sales test'' is the impact methodology EPA primarily employs in analyzing small entity impacts as opposed to a ''profits test,'' in which annualized compliance costs are calculated as a share of profits. The sales test is frequently used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. The use of a ''sales test'' for estimating small business impacts for a rulemaking is consistent with guidance offered by EPA on compliance with SBREFA [10] and is consistent with guidance published by the U.S. SBA's Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (U.S. SBA, 2010).[11]

Based on the analysis, we estimate that approximately 97 percent of all affected facilities have a cost-to-sales ratio of less than 1 percent. In addition, for approximately 1 percent of all affected facilities, or 9 facilities with fewer than 20 employees, the potential for cost-to-sales impacts may be between 3 and 9 percent. All of these facilities are in the hard chromium electroplating category, with 3 of the facilities in the small hard chromium electroplating category and 6 in the large hard chromium electroplating category. For these categories, because the average sales receipts used for the analysis may understate sales for some facilities and because these facilities are likely to be able to pass cost increases through to their customers, we do not anticipate the final rule to result in firm closures, significant price increases, or substantial profit loss. We conclude that this final rule will not have a significant economic impact on a substantial number of small entities. More information and details of this analysis are provided in the technical document ''Economic Impact Analysis for Risk and Technology Review: Chromium Electroplating and Chromium Anodizing Source Categories,'' which is available in the docket for this final rule.

2. Steel Pickling

Because only one of the approximately 100 facilities incurs any cost for controls and that cost is estimated to be less than 1 percent of sales, no significant price or productivity impacts are anticipated due to these amendments.

E. What are the benefits?

1. Chromium Electroplating and Chromium Anodizing

The estimated reductions in chromium emissions that will be achieved by this rule will provide benefits to public health. The limits will result in significant reductions in the actual and allowable emissions of hexavalent chromium therefore will reduce the actual and potential cancer risks due to emissions of chromium from this source category.

2. Steel Pickling

The estimated reductions in chlorine emissions that will result from this action will provide benefits to public health. The limits will result in reductions in the potential for noncancer health effects due to emissions of these HAP.

VI. 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 and policy issues. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

This action does not impose any new information collection requirements related to the Steel Pickling—HCl Process Facilities and Hydrochloric Acid Regeneration Plants MACT standards. However, the OMB has previously approved the information collection requirements contained in the existing regulations 40 CFR part 63, subpart CCC under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, et seq and assigned OMB Control Number 2060–0419.

The information collection requirements in this rule for the Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks NESHAP have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501, et seq. The Information Collection Request (ICR) document prepared was assigned EPA ICR number 1611.10. Burden changes associated with these amendments would result from the emission testing requirements and compliance demonstrations being promulgated with today's action. The estimated average burden per response is 9 hours; the frequency of response is one-time for all respondents that must comply with the rule's reporting requirements and the estimated average number of likely respondents per year is 485. The cost burden to respondents resulting from the collection of information includes the total capital cost annualized over the equipment's expected useful life ($100,958), a total operation and maintenance component ($0 per year), and a labor cost component (about $152,116 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 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

[9] *http://www.census.gov/econ/susb/data/susb2002.html.*

[10] The SBREFA compliance guidance to EPA rulewriters regarding the types of small business analysis that should be considered can be found at: *http://www.epa.gov/sbrefa/documents/Guidance-RegFlexAct.pdf.* See Table 2 on page 36 for guidance on interpretations of the magnitude of the cost-to-sales numbers.

[11] U.S. SBA, Office of Advocacy. A Guide for Government Agencies, How to Comply with the Regulatory Flexibility Act, Implementing the President's Small Business Agenda and Executive Order 13272, June 2010.

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 a small industrial entity 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 impact of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This rule imposes more stringent emissions limits and lower surface tension requirements. These new requirements and restrictions to the hard and decorative chromium electroplating and chromium anodizing tanks MACT standard will impact small entities, but those impacts have been estimated to be nominal. The emissions limits reflect the level of performance currently being achieved by most facilities, and many facilities currently have emissions that are far below the limits. With regard to the remaining facilities (those that will need to achieve emissions reductions), most of these facilities can achieve the limits at low costs (e.g., by using additional fume suppressants).

The EPA's analysis estimated that 97 percent of the affected entities will have an annualized cost of less than 1 percent of sales. In addition, approximately 1 percent of affected entities, or 9 facilities with fewer than 20 employees, may have cost-to-sales ratios between 3 to 9 percent. All of these facilities are in the hard chromium electroplating category, with 3 of the facilities in the small hard chromium electroplating category and 6 in the large hard chromium electroplating category.

Since our analysis indicates that a small subset of facilities (about 1 percent) may have cost-to-sales ratios greater than 3 percent, we have conducted additional economic impact analyses on this small subset of facilities to better understand the potential economic impacts for these facilities. The additional analyses indicate the estimates of costs-to-sales ratios in the initial analyses are more likely to be overstated rather than understated because the additional analyses indicate that sales are typically higher for these sources than the average value used in the initial analysis.

Moreover, because of the nature of the market, these facilities are likely to be able to pass cost increases through to their customers. As such, we do not anticipate the rule to result in firm closures, or substantial profit loss. More information and details of this analysis are provided in the technical document "Economic Impact Analysis for Risk and Technology Review: Chromium Electroplating," which is available in the docket for this final rule.

Although this 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.

D. Unfunded Mandates Reform Act

This rule 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 rule will 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 rule imposes no enforceable duties on any State, local, or tribal governments or the private sector. Thus, this rule is not subject to the requirements of sections 202 or 205 of the UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This action contains no requirements that apply to such governments nor does it impose obligations upon them.

E. Executive Order 13132: Federalism

This 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 facilities subject to this action are owned or operated by State governments and do not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to this rule.

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

This rule will 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 rule 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, some of the pollutants addressed by this action may present a disproportionate risk to children.[12] The phase-out of PFOS fume suppressants will help to reduce a disproportionate risk to children. This action will not relax the control measures on existing regulated sources and will result in reductions in cancer risks due to chromium emissions for people of all ages, including children. The EPA's risk assessments (included in the docket for this rule) demonstrate that these regulations, with the amendments being promulgated in today's action, will be health protective.

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 under Executive Order 13211, (66 FR 28355 (May 22, 2001)), because it is not likely to have 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.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory

[12] The EPA has not yet determined whether hexavalent chromium poses disproportionate risks to children by acting as a mutagenic carcinogen. The EPA is currently developing an IRIS assessment of hexavalent chromium which likely will address that issue.

activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

This rulemaking does not involve technical standards. Therefore, EPA is not considering 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.

To examine the potential for any environmental justice issues that might be associated with two of the source categories associated with today's rule (Hard Chromium Electroplaters and Decorative Chromium Electroplaters), we evaluated the percentages of various social, demographic, and economic groups within the at-risk populations living near the facilities where these source categories are located and compared them to national averages. We did not conduct this type of analysis for the chromic acid anodizing or steel pickling categories because the numbers of people for whom cancer risks were greater than 1-in-1 million due to HAP emissions from these source categories were low.

The analysis indicated that certain minority groups and low-income populations may be disproportionately exposed to emissions from these categories and to any risks that may result due to these emissions because the communities most proximate to facilities within these categories have a higher proportion of these groups than the national demographic profile. We did not, however, identify any vulnerability or susceptibility to risks particular to minority and low income populations from pollutants emitted from this source category.

We determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it maintains or increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority low-income, or indigenous populations. Further, after implementation of the provisions of this rule, the public health of all demographic groups will be protected with an ample margin of safety.

The development of demographic analyses to inform the consideration of environmental justice issues in EPA rulemakings is an evolving process. The EPA offers the demographic analyses in this rulemaking as examples of how such analyses might be developed to inform such consideration, with the hope that this will support the refinement and improve utility of such analyses for future rulemakings.

Our analysis of the demographics of the population with estimated risks greater than 1-in-1 million indicates potential disparities in risks between demographic groups, including the African American, Other and Multiracial, Hispanic, Below the Poverty Level, and the Over 25 without a High School Diploma groups. These groups stand to benefit the most from the emission reductions achieved by this rulemaking.

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 polices. To promote meaningful involvement, after the rule was proposed, EPA conducted a webinar to inform the public about the rule and to outline how to submit written comments to the docket. Further stakeholder and public input occurred through public comment and follow-up meetings with interested stakeholders.

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 September 19, 2012.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: August 15, 2012.

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—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.*

■ 2. Amend § 63.341 by:

■ a. Adding, in alphabetical order, in paragraph (a), definitions for "affirmative defense," "contains hexavalent chromium," "existing affected source," "new affected source," and "perfluorooctane sulfonic acid (PFOS)-based fume suppressant";

■ b. Revising in paragraph (a) the definition for "wetting agent"; and

■ c. Revising paragraph (b)(10).

The added and revised text reads as follows:

§ 63.341 Definitions and nomenclature.

(a) * * *

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.

* * * * *

Contains hexavalent chromium means, the substance consists of, or contains 0.1 percent or greater by weight, chromium trioxide, chromium (VI) oxide, chromic acid, or chromic anhydride.

* * * * *

Existing affected source means an affected hard chromium electroplating tank, decorative chromium electroplating tank, or chromium anodizing tank, the construction or

reconstruction of which commenced on or before February 8, 2012.

* * * * *

New affected source means an affected hard chromium electroplating tank, decorative chromium electroplating tank, or chromium anodizing tank, the construction or reconstruction of which commenced after February 8, 2012.

* * * * *

Perfluorooctane sulfonic acid (PFOS)-based fume suppressant means a fume suppressant that contains 1 percent or greater PFOS by weight.

* * * * *

Wetting agent means the type of commercially available chemical fume suppressant that materially reduces the surface tension of a liquid.

(b) * * *

(10) VR_{tot} = the average total ventilation rate for the three test runs as determined at the outlet by means of the Method 306 or 306A testing specified in appendix A of this part in dscm/min.

■ 3. Amend § 63.342 by:
■ a. Revising paragraph (a);
■ b. Revising paragraph (b)(1);
■ c. Revising paragraphs (c)(1)(i), (c)(1)(ii), and (c)(1)(iii);
■ d. Adding paragraphs (c)(1)(iv) and (c)(1)(v);
■ e. Revising paragraphs (c)(2)(i), (c)(2)(ii), (c)(2)(iii), and (c)(2)(iv);
■ f. Adding paragraphs (c)(2)(vi), (c)(2)(vii), and (c)(2)(viii);
■ g. Revising paragraphs (d)(1) and (d)(2);
■ h. Adding paragraphs (d)(3) and (d)(4);
■ i. Revising paragraph (e)(1);
■ j. Redesignating paragraphs (e)(2) and (e)(3) as paragraphs (e)(3) and (e)(4), and revising the newly designated paragraph (e)(4);
■ k. Adding a new paragraph (e)(2);
■ l. Adding paragraph (f)(3)(i)(F); and
■ m. Adding Table 2 to read as follows:

§ 63.342 Standards.

(a)(1) At all times, each owner or operator must operate and maintain any affected source subject to the requirements of this subpart, 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 the owner or operator 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.

(2) Each owner or operator of an affected source subject to the provisions of this subpart shall comply with these requirements in this section on and after the compliance dates specified in § 63.343(a). All affected sources are regulated by applying maximum achievable control technology.

(b) * * *

(1) The emission limitations in this section apply during tank operation as defined in § 63.341, and during periods of startup and shutdown as these are routine occurrences for affected sources subject to this subpart. In response to an action to enforce the standards set forth in this subpart, the owner or operator may assert a defense to a claim for civil penalties for violations of such standards that are caused by a malfunction, as defined in 40 CFR 63.2. Appropriate penalties may be assessed, however, if the owner or operator fails to meet the burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(i) To establish the affirmative defense in any action to enforce such a standard, the owner or operator must timely meet the reporting requirements of paragraph (b)(1)(ii) of this section, and must prove by a preponderance of evidence that:

(A) The violation was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal and usual manner; and could not have been prevented through careful planning, proper design or better operation and maintenance practices; and did not stem from any activity or event that could have been foreseen and avoided, or planned for; and was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

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

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

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

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

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

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

(H) At all times, the affected sources were operated in a manner consistent with good practices for minimizing emissions; and

(I) A written root cause analysis was 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 the best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

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

(c)(1) * * *

(i) Not allowing the concentration of total chromium in the exhaust gas stream discharged to the atmosphere to exceed 0.011 milligrams of total chromium per dry standard cubic meter (mg/dscm) of ventilation air (4.8×10^{-6} grains per dry standard cubic foot (gr/dscf)) for all open surface hard chromium electroplating tanks that are existing affected sources and are located at large hard chromium electroplating facilities; or

(ii) Not allowing the concentration of total chromium in the exhaust gas stream discharged to the atmosphere to

exceed 0.015 mg/dscm (6.6×10^{-6} gr/dscf) for all open surface hard chromium electroplating tanks that are existing affected sources and are located at small, hard chromium electroplating facilities; or

(iii) If a chemical fume suppressant containing a wetting agent is used, not allowing the surface tension of the electroplating or anodizing bath contained within the affected tank to exceed 40 dynes per centimeter (dynes/cm) (2.8×10^{-3} pound-force per foot (lbf/ft)), as measured by a stalagmometer, or 33 dynes/cm (2.3×10^{-3} lbf/ft), as measured by a tensiometer at any time during tank operation; or

(iv) Not allowing the concentration of total chromium in the exhaust gas stream discharged to the atmosphere to exceed 0.006 mg/dscm of ventilation air (2.6×10^{-6} gr/dscf) for all open surface hard chromium electroplating tanks that are new affected sources; or

(v) After September 21, 2015, the owner or operator of an affected open surface hard chromium electroplating tank shall not add PFOS-based fume suppressants to any affected open surface hard chromium electroplating tank.

(2) * * *

(i) Not allowing the concentration of total chromium in the exhaust gas stream discharged to the atmosphere to exceed 0.011 mg/dscm of ventilation air (4.8×10^{-6} gr/dscf) for all enclosed hard chromium electroplating tanks that are existing affected sources and are located at large hard chromium electroplating facilities; or

(ii) Not allowing the concentration of total chromium in the exhaust gas stream discharged to the atmosphere to exceed 0.015 mg/dscm (6.6×10^{-6} gr/dscf) for all enclosed hard chromium electroplating tanks that are existing affected sources and are located at small, hard chromium electroplating facilities; or

(iii) If a chemical fume suppressant containing a wetting agent is used, not allowing the surface tension of the electroplating or anodizing bath contained within the affected tank to exceed 40 dynes/cm (2.8×10^{-3} lbf/ft), as measured by a stalagmometer, or 33 dynes/cm (2.3×10^{-3} lbf/ft), as measured by a tensiometer at any time during tank operation; or

(iv) Not allowing the mass rate of total chromium in the exhaust gas stream discharged to the atmosphere to exceed the maximum allowable mass emission rate determined by using the calculation procedure in § 63.344(f)(1)(i) for all enclosed hard chromium electroplating tanks that are existing affected sources and are located at large hard chromium electroplating facilities; or

* * * * *

(vi) Not allowing the concentration of total chromium in the exhaust gas stream discharged to the atmosphere to exceed 0.006 mg/dscm of ventilation air (2.6×10^{-6} gr/dscf) for all enclosed hard chromium electroplating tanks that are new affected sources; or

(vii) Not allowing the mass rate of total chromium in the exhaust gas stream discharged to the atmosphere to exceed the maximum allowable mass emission rate determined by using the calculation procedure in § 63.344(f)(1)(iii) if the enclosed hard chromium electroplating tank is a new affected source.

(viii) After September 21, 2015, the owner or operator of an affected enclosed hard chromium electroplating tank shall not add PFOS-based fume suppressants to any affected enclosed hard chromium electroplating tank.

(d) * * *

(1) Not allowing the concentration of total chromium in the exhaust gas stream discharged to the atmosphere to exceed 0.007 mg/dscm (3.1×10^{-6} gr/dscf) for all existing decorative chromium electroplating tanks using a chromic acid bath and all existing chromium anodizing tanks; or

(2) Not allowing the concentration of total chromium in the exhaust gas stream discharged to the atmosphere to exceed 0.006 mg/dscm (2.6×10^{-6} gr/dscf) for all new or reconstructed decorative chromium electroplating tanks using a chromic acid bath and all new or reconstructed chromium anodizing tanks; or

(3) If a chemical fume suppressant containing a wetting agent is used, not allowing the surface tension of the electroplating or anodizing bath contained within the affected tank to exceed 40 dynes/cm (2.8×10^{-3} lbf/ft), as measured by a stalagmometer or 33 dynes/cm (2.3×10^{-3} lbf/ft), as measured by a tensiometer at any time during tank operation, for all existing, new, or reconstructed decorative chromium electroplating tanks using a chromic acid bath and all existing, new, or reconstructed chromium anodizing tanks; or

(4) After September 21, 2015, the owner or operator of an affected decorative chromium electroplating tank or an affected chromium anodizing tank shall not add PFOS-based fume suppressants to any affected decorative chromium electroplating tank or chromium anodizing tank.

(e) * * *

(1) Each owner or operator of an existing, new, or reconstructed decorative chromium electroplating tank that uses a trivalent chromium bath that incorporates a wetting agent as a bath ingredient is subject to the recordkeeping and reporting requirements of §§ 63.346(b)(14) and 63.347(i), but are not subject to the work practice requirements of paragraph (f) of this section, or the continuous compliance monitoring requirements in § 63.343(c). The wetting agent must be an ingredient in the trivalent chromium bath components purchased as a package.

(2) After September 21, 2015, the owner or operator of an affected decorative chromium electroplating tank using a trivalent chromium bath shall not add PFOS-based fume suppressants to any affected decorative chromium electroplating tank.

* * * * *

(4) Each owner or operator of an existing, new, or reconstructed decorative chromium electroplating tank that had been using a trivalent chromium bath that incorporated a wetting agent and ceases using this type of bath must fulfill the reporting requirements of § 63.347(i)(3) and comply with the applicable emission limitation within the timeframe specified in § 63.343(a)(7).

(f) * * *

(3) * * *

(i) * * *

(F) The plan shall include housekeeping procedures, as specified in Table 2 of this section.

* * * * *

TABLE 2 TO § 63.342—HOUSEKEEPING PRACTICES

For	You must:	At this minimum frequency
1. Any substance used in an affected chromium electroplating or chromium anodizing tank that contains hexavalent chromium.	(a) Store the substance in a closed container in an enclosed storage area or building; AND (b) Use a closed container when transporting the substance from the enclosed storage area.	At all times, except when transferring the substance to and from the container. Whenever transporting substance, except when transferring the substance to and from the container.
2. Each affected tank, to minimize spills of bath solution that result from dragout. Note: this measure does not require the return of contaminated bath solution to the tank. This requirement applies only as the parts are removed from the tank. Once away from the tank area, any spilled solution must be handled in accordance with Item 4 of these housekeeping measures.	(a) Install drip trays that collect and return to the tank any bath solution that drips or drains from parts as the parts are removed from the tank; OR (b) Contain and return to the tank any bath solution that drains or drips from parts as the parts are removed from the tank; OR (c) Collect and treat in an onsite wastewater treatment plant any bath solution that drains or drips from parts as the parts are removed from the tank.	Prior to operating the tank. Whenever removing parts from an affected tank. Whenever removing parts from an affected tank.
3. Each spraying operation for removing excess chromic acid from parts removed from, and occurring over, an affected tank.	Install a splash guard to minimize overspray during spraying operations and to ensure that any hexavalent chromium laden liquid captured by the splash guard is returned to the affected chromium electroplating or anodizing tank.	Prior to any such spraying operation.
4. Each operation that involves the handling or use of any substance used in an affected chromium electroplating or chromium anodizing tank that contains hexavalent chromium.	Begin clean up, or otherwise contain, all spills of the substance. Note: substances that fall or flow into drip trays, pans, sumps, or other containment areas are not considered spills.	Within 1 hour of the spill.
5. Surfaces within the enclosed storage area, open floor area, walkways around affected tanks contaminated with hexavalent chromium from an affected chromium electroplating or chromium anodizing tank.	(a) Clean the surfaces using one or more of the following methods: HEPA vacuuming; Hand-wiping with a damp cloth; Wet mopping; Hose down or rinse with potable water that is collected in a wastewater collection system; Other cleaning method approved by the permitting authority; OR (b) Apply a non-toxic chemical dust suppressant to the surfaces.	At least once every 7 days if one or more chromium electroplating or chromium anodizing tanks were used, or at least after every 40 hours of operating time of one or more affection chromium electroplating or chromium anodizing tank, whichever is later. According to manufacturer's recommendations.
6. All buffing, grinding, or polishing operations that are located in the same room as chromium electroplating or chromium anodizing operations.	Separate the operation from any affected electroplating or anodizing operation by installing a physical barrier; the barrier may take the form of plastic strip curtains.	Prior to beginning the buffing, grinding, or polishing operation.
7. All chromium or chromium-containing wastes generated from housekeeping activities.	Store, dispose, recover, or recycle the wastes using practices that do not lead to fugitive dust and in accordance with hazardous waste requirements.	At all times.

■ 4. Section 63.343 is amended by:
■ a. Revising paragraphs (a)(1), (a)(2), and (a)(4), and adding paragraph (a)(8);
■ b. Revising paragraph (b)(1); and
■ c. Revising paragraphs (c) introductory text, (c)(1)(ii), (c)(2)(ii), (c)(4)(ii), (c)(5)(i), (c)(5)(ii), and (c)(6)(ii).

The added and revised text reads as follows:

§ 63.343 Compliance provisions.

(a)(1) The owner or operator of an existing affected source shall comply with the emission limitations in § 63.342 no later than September 19, 2014.

(2) The owner or operator of a new or reconstructed affected source that has an initial startup after September 19, 2012, shall comply immediately upon startup of the source.

* * * * *

(4) The owner or operator of a new area source (i.e., an area source for which construction or reconstruction was commenced after February 8, 2012, that increases actual or potential emissions of hazardous air pollutants such that the area source becomes a major source must comply with the provisions for new major sources, immediately upon becoming a major source.

* * * * *

(8) After March 19, 2013, the owner or operator of an affected source that is subject to the standards in paragraphs § 63.342(c) or (d) shall implement the housekeeping procedures specified in Table 2 of § 63.342.

(b) *Methods to demonstrate initial compliance.* (1) Except as provided in paragraphs (b)(2) and (b)(3) of this section, an owner or operator of an affected source subject to the requirements of this subpart is required to conduct an initial performance test as required under § 63.7, using the procedures and test methods listed in §§ 63.7 and 63.344.

* * * * *

(c) *Monitoring to demonstrate continuous compliance.* The owner or operator of an affected source subject to the emission limitations of this subpart shall conduct monitoring according to the type of air pollution control technique that is used to comply with the emission limitation. The monitoring required to demonstrate continuous compliance with the emission limitations is identified in this section for the air pollution control techniques expected to be used by the owners or

operators of affected sources. As an alternative to the daily monitoring, the owner or operator of an affected source may install a continuous pressure monitoring system.

* * * * *

(c) * * *

(1) * * *

(ii) On and after the date on which the initial performance test is required to be completed under § 63.7, the owner or operator of an affected source, or group of affected sources under common control, shall monitor and record the pressure drop across the composite mesh-pad system once each day that any affected source is operating. To be in compliance with the standards, the composite mesh-pad system shall be operated within ±2 inches of water column of the pressure drop value established during the initial performance test, or shall be operated within the range of compliant values for pressure drop established during multiple performance tests.

* * * * *

(2) * * *

(ii) On and after the date on which the initial performance test is required to be completed under § 63.7, the owner or operator of an affected source, or group of affected sources under common control, shall monitor and record the velocity pressure at the inlet to the packed-bed system and the pressure drop across the scrubber system once each day that any affected source is operating. To be in compliance with the standards, the scrubber system shall be operated within ±10 percent of the velocity pressure value established during the initial performance test, and within ±1 inch of water column of the pressure drop value established during the initial performance test, or within the range of compliant operating parameter values established during multiple performance tests.

* * * * *

(4) * * *

(ii) On and after the date on which the initial performance test is required to be completed under § 63.7, the owner or operator of an affected source, or group of affected sources under common control, shall monitor and record the pressure drop across the fiber-bed mist eliminator, and the control device installed upstream of the fiber bed to prevent plugging, once each day that any affected source is operating. To be in compliance with the standards, the fiber-bed mist eliminator and the upstream control device shall be operated within ±1 inch of water column of the pressure drop value established during the initial performance test, or shall be operated within the range of compliant values for pressure drop established during multiple performance tests.

* * * * *

(5) *Wetting agent-type or combination wetting agent-type/foam blanket fume suppressants.* (i) During the initial performance test, the owner or operator of an affected source complying with the emission limitations in § 63.342 through the use of a wetting agent in the electroplating or anodizing bath shall determine the outlet chromium concentration using the procedures in § 63.344(c). The owner or operator shall establish as the site-specific operating parameter the surface tension of the bath using Method 306B, appendix A of this part, setting the maximum value that corresponds to compliance with the applicable emission limitation. In lieu of establishing the maximum surface tension during the performance test, the owner or operator may accept 40 dynes/cm, as measured by a stalagmometer, or 33 dynes/cm, as measured by a tensiometer, as the maximum surface tension value that corresponds to compliance with the applicable emission limitation. However, the owner or operator is exempt from conducting a performance test only if the criteria of paragraph (b)(1) of this section are met.

(ii) On and after the date on which the initial performance test is required to be completed under § 63.7, the owner or operator of an affected source shall monitor the surface tension of the electroplating or anodizing bath. Operation of the affected source at a surface tension greater than the value established during the performance test, or greater than 40 dynes/cm, as measured by a stalagmometer, or 33 dynes/cm, as measured by a tensiometer, if the owner or operator is using this value in accordance with paragraph (c)(5)(i) of this section, shall constitute noncompliance with the standards. The surface tension shall be monitored according to the following schedule:

* * * * *

(6) * * *

(ii) On and after the date on which the initial performance test is required to be completed under § 63.7, the owner or operator of an affected source shall monitor the foam blanket thickness of the electroplating or anodizing bath. Operation of the affected source at a foam blanket thickness less than the value established during the performance test, or less than 2.54 cm (1 inch) if the owner or operator is using this value in accordance with paragraph (c)(6)(i) of this section, shall constitute noncompliance with the standards. The foam blanket thickness shall be measured according to the following schedule:

* * * * *

■ 5. Section 63.344 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Removing "and" from the end of paragraph (b)(1)(iii);

■ c. Removing the period from the end of paragraph (b)(1)(iv) and adding "; and" in its place;

■ d. Adding paragraphs (b)(1)(v) through (b)(1)(viii);

■ e. Removing and reserving paragraph (b)(2);

■ f. Revising paragraph (c)(1);

■ g. Revising paragraphs (e)(3)(iii), (e)(3)(iv), and (e)(3)(v);

■ h. Revising paragraphs (e)(4)(ii) and (e)(4)(iv);

■ i. Revising paragraphs (f)(1)(i)(A) and (f)(1)(ii)(A); and

■ j. Adding paragraph (f)(1)(iii).

The added and revised text reads as follows:

§ 63.344 Performance test requirements and test methods.

(a) *Performance test requirements.* Performance tests shall be conducted using the test methods and procedures in this section. 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. Performance test results shall be documented in complete test reports that contain the information required by paragraphs (a)(1) through (9) of this section. The test plan to be followed shall be made available to the Administrator prior to the testing, if requested.

* * * * *

(b)(1) * * *

(v) The performance test was conducted after January 25, 1995;

(vi) As of September 19, 2012 the source was using the same emissions controls that were used during the compliance test;

(vii) As of September 19, 2012, the source was operating under conditions that are representative of the conditions under which the source was operating during the compliance test; and

(viii) Based on approval from the permitting authority.

* * * * *

(c) * * *

(1) Method 306 or Method 306A, ''Determination of Chromium Emissions From Decorative and Hard Chromium Electroplating and Anodizing Operations,'' appendix A of this part shall be used to determine the chromium concentration from hard or decorative chromium electroplating tanks or chromium anodizing tanks. The sampling time and sample volume for each run of Methods 306 and 306A, appendix A of this part shall be at least 120 minutes and 1.70 dscm (60 dscf), respectively. Methods 306 and 306A, appendix A of this part allow the measurement of either total chromium or hexavalent chromium emissions. For the purposes of this standard, sources using chromic acid baths must demonstrate compliance with the emission limits of § 63.342 by measuring the total chromium.

* * * * *

(e) * * *

(3) * * *

(iii) Perform Method 306 or 306A testing and calculate an outlet mass emission rate.

(iv) Determine the total ventilation rate from the affected sources (VR_{inlet}) by using equation 1:

$$VR_{tot} \times \frac{IDA_i}{\sum IA_{total}} = VR_{inlet} \quad (1)$$

where VR_{tot} is the average total ventilation rate in dscm/min for the three test runs as determined at the outlet by means of the Method 306 or 306A testing; IDA_i is the total inlet area for all ducts associated with affected sources; ΣIA_{total} is the sum of all inlet duct areas from both affected and nonaffected sources; and VR_{inlet} is the total ventilation rate from all inlet ducts associated with affected sources.

(v) Establish the allowable mass emission rate of the system (AMR_{sys}) in milligrams of total chromium per hour (mg/hr) using equation 2:

$$\sum VR_{inlet} \times EL \times 60 \text{ minutes/hour} = AMR_{sys} \quad (2)$$

where ΣVR_{inlet} is the total ventilation rate in dscm/min from the affected sources, and EL is the applicable emission limitation from § 63.342 in mg/dscm. The allowable mass emission rate (AMR_{sys}) calculated from equation 2 should be equal to or more than the outlet three-run average mass emission rate determined from Method 306 or 306A testing in order for the source to be in compliance with the standard.

(4) * * *

(ii) Determine the total ventilation rate for each type of affected source ($VR_{inlet,a}$) using equation 3:

$$VR_{tot} \times \frac{IDA_{i,a}}{\sum IA_{total}} = VR_{inlet,a} \quad (3)$$

where VR_{tot} is the average total ventilation rate in dscm/min for the three test runs as determined at the outlet by means of the Method 306 or 306A testing; $IDA_{i,a}$ is the total inlet duct area for all ducts conveying chromic acid from each type of affected source performing the same operation, or each type of affected source subject to the same emission limitation; ΣIA_{total} is the sum of all duct areas from both affected and nonaffected sources; and $VR_{inlet,a}$ is the total ventilation rate from all inlet ducts conveying chromic acid from each type of affected source performing the same operation, or each type of affected source subject to the same emission limitation.

* * * * *

(iv) Establish the allowable mass emission rate of the system (AMR_{sys}) in milligrams of total chromium per hour (mg/hr) using equation 8, including each type of affected source as appropriate:

$$AMR_{hc1} + AMR_{hc2} + AMR_{dc} + AMR_{ca} = AMR_{sys} \quad (8)$$

The allowable mass emission rate calculated from equation 8 should be equal to or more than the outlet three-run average mass emission rate determined from Method 306 or 306A testing in order for the source to be in compliance with the standards.

* * * * *

(f) * * *

(1) * * *

(i)(A) The owner or operator of an enclosed hard chromium electroplating tank that is an existing affected source and is located at a large hard chromium electroplating facility who chooses to meet the mass emission rate standard in § 63.342(c)(2)(iv) shall determine compliance by not allowing the mass rate of total chromium in the exhaust gas stream discharged to the atmosphere to exceed the maximum allowable mass emission rate calculated using equation 9:

$$MAMER = ETSA \times K \times 0.011 \text{ mg/dscm} \quad (9)$$

* * * * *

(ii)(A) The owner or operator of an enclosed hard chromium electroplating tank that is an existing affected source located at a small hard chromium electroplating facility who chooses to meet the mass emission rate standard in § 63.342(c)(2)(v) shall determine compliance by not allowing the mass rate of total chromium in the exhaust gas stream discharged to the atmosphere to exceed the maximum allowable mass

emission rate calculated using equation 10:

$$MAMER = ETSA \times K \times 0.015 \text{ mg/dscm.} \quad (10)$$

* * * * *

(iii)(A) The owner or operator of an enclosed hard chromium electroplating tank that is a new source who chooses to meet the mass emission rate standard in § 63.342(c)(2)(vii) shall determine compliance by not allowing the mass rate of total chromium in the exhaust gas stream discharged to the atmosphere to exceed the maximum allowable mass emission rate calculated using equation 11:

$$MAMER = ETSA \times K \times 0.006 \text{ mg/dscm.} \quad (11)$$

(B) Compliance with the alternative mass emission limit is demonstrated if the three-run average mass emission rate determined from testing using Method 306 or 306A of appendix A to part 63 is less than or equal to the maximum allowable mass emission rate calculated from equation 11.

■ 6. Amend § 63.346 by revising paragraphs (b)(2),(b)(4) and (b)(13) to read as follows:

§ 63.346 Recordkeeping requirements.

* * * * *

(b) * * *

(2) Records of all maintenance performed on the affected source, the add-on air pollution control device, and monitoring equipment, except routine housekeeping practices;

* * * * *

(4) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.342(a)(1), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation;

* * * * *

(13) For sources using fume suppressants to comply with the standards, records of the date and time that fume suppressants are added to the electroplating or anodizing bath and records of the fume suppressant manufacturer and product name;

* * * * *

■ 7. Amend § 63.347 by:

■ a. Adding paragraph (f)(3);

■ b. Redesignating paragraphs (g)(3)(xii) and (g)(3)(xiii) as (g)(3)(xiii) and (g)(3)(xiv), respectively, and adding a new paragraph (g)(3)(xii); and

■ c. Revising paragraphs (h)(2)(i) introductory text and (h)(2)(i)(A) to read as follows:

§ 63.347 Reporting requirements.

* * * * *

(f) * * *

(3)(i) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart, you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk, flash drive or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

* * * * *

(g) * * *

(3) * * *

(xii) 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 § 63.342(a)(1), including actions taken to correct a malfunction.

(xiii) The name, title, and signature of the responsible official who is certifying the accuracy of the report; and

(xiv) The date of the report.

* * * * *

(h) * * *

(2) * * *

(i) If either of the following conditions is met, semiannual reports shall be prepared and submitted to the Administrator:

(A) The total duration of excess emissions (as indicated by the monitoring data collected by the owner or operator of the affected source in accordance with § 63.343(c)) is 1 percent or greater of the total operating time for the reporting period; or

* * * * *

■ 8. Amend Table 1 to Subpart N by:

■ a. Adding in alphanumerical order entries 63.1(a)(5), 63.1(a)(7)–(9), 63.1(a)(12), 63.1(c)(3)–(4), 63.4(a)(1)–(2), 63.4(a)(3)–(5), 63.4(b)–(c), 63.5(b)(2), 63.5(c), 63.6(c)(3)–(4), 63.6(d), 63.6(e)(1)–(3), 63.6(h)(1), 63.6(h)(2), 63.6(i)(15), 63.7(a)(2)(i)–(viii), 63.7(a)(4), 63.7(e)(1), 63.7(e)(2)–(4), 63.7(g)(2), 63.8(a)(3), and 63.9(h)(4).

■ b. Removing entries 63.1(a)(7) and 63.1 (a)(8), 63.1(a)(12)—(a)(14), 63.1(c)(4), 63.4, 63.6(e), 63.6(h), 63.7(a)(2)(i)–(vi), and 63.7(e).

■ c. Revising entries 63.1(b)(2), 63.5(b)(5), 63.6(b)(6), and 63.9(b)(3),

The added and revised text reads as follows:

TABLE 1 TO SUBPART N OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART N

General provisions reference	Applies to subpart N	Comment
* * *	*	* * *
63.1(a)(5)	No	[Reserved]
* * *	*	* * *
63.1(a)(7)–(9)	No	[Reserved]
* * *	*	* * *
63.1(a)(12)	Yes	
* * *	*	* * *
63.1(b)(2)	No	[Reserved]
* * *	*	* * *
63.1(c)(3)–(4)	No	[Reserved]
* * *	*	* * *
63.4(a)(1)–(2)	Yes.	
63.4(a)(3)–(5)	No	[Reserved]
63.4(b)–(c)	Yes.	
* * *	*	* * *
63.5(b)(2)	No	[Reserved]
* * *	*	* * *
63.5(b)(5)	No	[Reserved]
* * *	*	* * *
63.5(c)	No	[Reserved]
* * *	*	* * *
63.6(b)(6)	No	[Reserved]
* * *	*	* * *
63.6(c)(3)–(4)	No	[Reserved]
* * *	*	* * *
63.6(d)	No	[Reserved]
63.6(e)(1)–(3)	No	§ 63.342(f) of subpart N contains work practice standards (operation and maintenance requirements) that override these provisions.
* * *	*	* * *
63.6(h)(1)	No	SSM Exception
63.6(h)(2)	No	Subpart N does not contain any opacity or visible emission standards.
* * *	*	* * *
63.6(i)(15)	No	[Reserved]
* * *	*	* * *
63.7(a)(2)(i)–(viii)	No	[Reserved]
* * *	*	* * *
63.7(a)(4)	Yes	
* * *	*	* * *
63.7(e)(1)	No	See § 63.344(a). Any cross reference to § 63.7(e)(1) in any other general provision incorporated by reference shall be treated as a cross-reference to § 63.344(a).
63.7(e)(2)–(4)	Yes	Subpart N also contains test methods specific to affected sources covered by that subpart.
* * *	*	* * *
63.7(g)(2)	No	[Reserved]
* * *	*	* * *
63.8(a)(3)	No	[Reserved]
* * *	*	* * *
63.9(b)(3)	No	[Reserved]
* * *	*	* * *
63.9(h)(4)	No	[Reserved]

TABLE 1 TO SUBPART N OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART N—Continued

General provisions reference	Applies to subpart N	Comment
* * *	* * *	* * *

Subpart CCC—[AMENDED]

■ 9. Section 63.1155 is amended by adding paragraph (d) to read as follows:

§ 63.1155 Applicability.

* * * * *

(d) In response to an action to enforce the standards set forth in this subpart, the owner or operator may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by a malfunction, as defined in § 63.2. Appropriate penalties may be assessed, however, if the owner or operator fails to meet the 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 standard, the owner or operator must timely meet the reporting requirements of paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The violation was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal and usual manner; and could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and did not stem from any activity or event that could have been foreseen and avoided, or planned for; and was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

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

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

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

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

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

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

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

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

(2) *Report.* The owner of operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmation defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 10. Section 63.1156 is amended by adding in alphabetical order a definition for ''affirmative defense'' to read as follows:

§ 63.1156 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.

* * * * *

■ 11. Section 63.1157 is amended by revising paragraph (b)(2) to read as follows:

§ 63.1157 Emission standards for existing sources.

* * * * *

(b) * * *

(2) In addition to the requirement of paragraph (b)(1) of this section, no owner or operator of an existing plant shall cause or allow to be discharged into the atmosphere from the affected plant any gases that contain chlorine (Cl_2) in a concentration in excess of 6 ppmv.

■ 12. Section 63.1159 is amended by adding paragraph (c) to read as follows:

§ 63.1159 Operational and equipment standards for existing, new, or reconstructed sources.

* * * * *

(c) *General duty to minimize emissions.* At all times, each owner or operator must operate and maintain any affected source subject to the requirements of this subpart, 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 the owner or operator 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.

■ 13. Section 63.1160 is amended by revising paragraph (b) to read as follows:

§ 63.1160 Compliance dates and maintenance requirements.

* * * * *

(b) *Maintenance requirements.* (1) The owner or operator shall prepare an

operation and maintenance plan for each emission control device to be implemented no later than the compliance date. The plan shall be incorporated by reference into the source's title V permit. All such plans must be consistent with good maintenance practices, and, for a scrubber emission control device, must at a minimum:

(i) Require monitoring and recording the pressure drop across the scrubber once per shift while the scrubber is operating in order to identify changes that may indicate a need for maintenance;

(ii) Require the manufacturer's recommended maintenance at the recommended intervals on fresh solvent pumps, recirculating pumps, discharge pumps, and other liquid pumps, in addition to exhaust system and scrubber fans and motors associated with those pumps and fans;

(iii) Require cleaning of the scrubber internals and mist eliminators at intervals sufficient to prevent buildup of solids or other fouling;

(iv) Require an inspection of each scrubber at intervals of no less than 3 months with:

(A) Cleaning or replacement of any plugged spray nozzles or other liquid delivery devices;

(B) Repair or replacement of missing, misaligned, or damaged baffles, trays, or other internal components;

(C) Repair or replacement of droplet eliminator elements as needed;

(D) Repair or replacement of heat exchanger elements used to control the temperature of fluids entering or leaving the scrubber; and

(E) Adjustment of damper settings for consistency with the required air flow.

(v) If the scrubber is not equipped with a viewport or access hatch allowing visual inspection, alternate means of inspection approved by the Administrator may be used.

(vi) The owner or operator shall initiate procedures for corrective action within 1 working day of detection of an operating problem and complete all corrective actions as soon as practicable. Procedures to be initiated are the applicable actions that are specified in the maintenance plan. Failure to initiate or provide appropriate repair, replacement, or other corrective action is a violation of the maintenance requirement of this subpart.

(vii) The owner or operator shall maintain a record of each inspection, including each item identified in paragraph (b)(2)(iv) of this section, that is signed by the responsible maintenance official and that shows the date of each inspection, the problem identified, a description of the repair, replacement, or other corrective action taken, and the date of the repair, replacement, or other corrective action taken.

(2) The owner or operator of each hydrochloric acid regeneration plant shall develop and implement a written maintenance program. The program shall require:

(i) Performance of the manufacturer's recommended maintenance at the recommended intervals on all required systems and components;

(ii) Initiation of procedures for appropriate and timely repair, replacement, or other corrective action within 1 working day of detection; and

(iii) Maintenance of a daily record, signed by a responsible maintenance official, showing the date of each inspection for each requirement, the problems found, a description of the repair, replacement, or other action taken, and the date of repair or replacement.

■ 14. Section 63.1161 is amended by:
■ a. Revising paragraph (a); and
■ b. Removing and reserving paragraph (c)(2).

§ 63.1161 Performance testing and test methods.

(a) *Demonstration of compliance.* The owner or operator shall conduct an initial performance test for each process or emission control device to determine and demonstrate compliance with the applicable emission limitation according to the requirements in § 63.7 of subpart A of this part and in this section. 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.

* * * * *

■ 15. Section 63.1164 is amended by:
■ a. Revising paragraph (a); and
■ b. Revising paragraph (c).

§ 63.1164 Reporting requirements.

(a) *Reporting results of performance tests.* Within 60 days after the date of completing each performance test (defined in § 63.2), as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/;cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk, flash drive or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

* * * * *

(c) *Reporting malfunctions.* 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 shall be stated in a semiannual report. 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 § 63.1159(c), including actions taken to correct a malfunction. The report, to be certified by the owner or operator or other responsible official, shall be submitted semiannually and delivered or postmarked by the 30th day following the end of each calendar half.

■ 16. Section 63.1165 is amended by:
■ a. Revising paragraph (a)(1);
■ b. Revising paragraph (a)(4);
■ c. Removing paragraph (a)(5), and redesignating paragraphs (a)(6) through (a)(11) as (a)(5) through (a)(10).

The revisions read as follows:

§ 63.1165 Recordkeeping requirements.

(a) * * *

(1) The occurrence and duration of each malfunction of operation (*i.e.*, process equipment);

* * * * *

(4) Actions taken during periods of malfunction to minimize emissions in accordance with § 63.1259(c) and the dates of such actions (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation);

* * * * *

■ 17. Table 1 to Subpart CCC is amended by:

■ a. Removing entry 63.6(a)–(g);

■ b. Adding entry 63.6(a)–(d) in alphanumerical order;

■ c. 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), 63.6(f)(2)–(3), and 63.6(g) in alphanumerical order;

■ d. Removing entry 63.7–63.9;

■ e. Adding entries 63.7, 63.8(a)–(c), 63.8(d)(1)–(2), 63.8(d)(3), and 63.8(e)–(f) in alphanumerical order;

■ f. Removing entry 63.10(a)–(c);

■ 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)–(v), 63.10(b)(2)(vi)–(xiv), 63.10(b)(3), 63.10(c)(1)–(9), 63.10(c)(10), 63.10(c)(11), 63.10(c)(12)–(14), and 63.10(c)(15) in alphanumerical order;

■ h. Removing entry 63.10(d)(4)–(5); and

■ i. Adding entries 63.10(d)(4) and 63.10(d)(5) in alphanumerical order.

The additions read as follows:

TABLE 1 TO SUBPART CCC OF PART 63—APPLICABILITY OF GENERAL PROVISIONS (40 CFR PART 63, SUBPART A) TO SUBPART CCC

Reference	Applies to subpart CCC	Explanation
*	*	*
63.6 (a)–(d)	Yes.	
63.6(e)(1)(i)	No	See § 63.1259(c) for general duty requirement. Any cross-reference to § 63.6(e)(1)(i) in any other general provision incorporated by reference shall be treated as a cross-reference to § 63.1259(c).
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)–(3)	Yes.	
63.6(g)	Yes.	
*	*	*
63.7	Yes.	
63.8(a)–(c)	Yes.	
63.8(d)(1)–(2)	Yes.	
63.8(d)(3)	Yes, except for last sentence.	
63.8(e)–(f)	Yes.	
*	*	*
63.10(a)	Yes.	
63.10(b)(1)	Yes.	
63.10(b)(2)(i)	No.	
63.10(b)(2)(ii)	No	See § 63.1265(a)(1) for recordkeeping of occurrence and duration of malfunctions. See § 63.1265(a)(4) for recordkeeping of actions taken during malfunction. Any cross-reference to § 63.10(b)(2)(ii) in any other general provision incorporated by reference shall be treated as a cross-reference to § 63.1265(a)(1).
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)	No	See § 63.1164(c) for reporting malfunctions. Any cross-reference to § 63.10(c)(10) in any other general provision incorporated by reference shall be treated as a cross-reference to § 63.1164(c).
63.10(c)(11)	No	See § 63.1164(c) for reporting malfunctions. Any cross-reference to § 63.10(c)(11) in any other general provision incorporated by reference shall be treated as a cross-reference to § 63.1164(c).
63.10(c)(12)–(c)(14)	Yes.	
63.10(c)(15)	No.	
63.10(d)(4)	Yes.	
63.10(d)(5)	No.	
*	*	*

■ 18. Amend Appendix A to part 63, Method 306B by:

■ a. Revising paragraph 1.2;

■ b. Revising paragraph 6.1;

■ c. Revising paragraphs 11.1 through 11.1.3; and

■ d. Revising paragraph 11.2.2.

■ The added and revised text reads as follows:

Appendix A to Part 63—Test Methods Pollutant Measurement Methods From Various Waste Media

* * * * *

METHOD 306B—SURFACE TENSION MEASUREMENT FOR TANKS USED AT DECORATIVE CHROMIUM ELECTROPLATING AND CHROMIUM ANODIZING FACILITIES

* * * * *

1.0 Scope and Application

* * * * *

1.2 Applicability. This method is applicable to all chromium electroplating and chromium anodizing operations, and continuous chromium plating at iron and steel facilities where a wetting agent is used in the tank as the primary mechanism for reducing emissions from the surface of the plating solution.

* * * * *

6.0 Equipment and Supplies

6.1 Stalagmometer. Any commercially available stalagmometer or equivalent surface tension measuring device may be used to measure the surface tension of the plating or anodizing tank liquid provided the procedures specified in Section 11.1.2 are followed.

* * * * *

11.0 Analytical Procedure

11.1 Procedure. The surface tension of the tank bath may be measured using a tensiometer, stalagmometer, or any other equivalent surface tension measuring device for measuring surface tension in dynes per centimeter.

11.1.1 If a tensiometer is used, the procedures specified in ASTM Method D 1331–89 must be followed.

11.1.2 If a stalagmometer is used, the procedures specified in Sections 11.1.2.1 through 11.1.2.3 must be followed.

11.1.2.1 Check the stalagmometer for visual signs of damage. If the stalagmometer appears to be chipped, cracked, or otherwise in disrepair, the instrument shall not be used.

11.1.2.2 Using distilled or deionized water and following the procedures provided by the manufacturer, count the number of drops corresponding to the distilled/deionized water liquid volume between the upper and lower etched marks on the stalagmometer. If the number of drops for the distilled/deionized water is not within ±1 drop of the number indicated on the instrument, the stalagmometer must be cleaned, using the procedures specified in Section 11.1.3 of this method, before using the instrument to measure the surface tension of the tank liquid.

11.1.2.2.1 If the stalagmometer must be cleaned, as indicated in Section 11.1.2.2, repeat the procedure specified in Section 11.1.2.2 before proceeding.

11.1.2.2.2 If, after cleaning and performing the procedure in Section 11.1.2.2, the number of drops indicated for the distilled/deionized water is not within ±1 drop of the number indicated on the instrument, either use the number of drops corresponding to the distilled/deionized water volume as the reference number of drops, or replace the instrument.

11.1.2.3 Determine the surface tension of the tank liquid using the procedures specified by the manufacturer of the stalagmometer.

11.1.3 *Stalagmometer cleaning procedures.* The procedures specified in Sections 11.1.3.1 through 11.1.3.10 shall be used for cleaning a stalagmometer, as required by Section 11.1.2.2.

11.1.3.1 Set up the stalagmometer on its stand in a fume hood.

11.1.3.2 Place a clean 150 (mL) beaker underneath the stalagmometer and fill the beaker with reagent grade concentrated nitric acid.

11.1.3.3 Immerse the bottom tip of the stalagmometer (approximately 1 centimeter (0.5 inches)) into the beaker.

11.1.3.4 Squeeze the rubber bulb and pinch at the arrow up (1) position to collapse.

11.1.3.5 Place the bulb end securely on top end of stalagmometer and carefully draw the nitric acid by pinching the arrow up (1) position until the level is above the top etched line.

11.1.3.6 Allow the nitric acid to remain in stalagmometer for 5 minutes, then carefully remove the bulb, allowing the acid to completely drain.

11.1.3.7 Fill a clean 150 mL beaker with distilled or deionized water.

11.1.3.8 Using the rubber bulb per the instructions in Sections 11.1.3.4 and 11.1.3.5, rinse and drain stalagmometer with deionized or distilled water.

11.1.3.9 Fill a clean 150 mL beaker with isopropyl alcohol.

11.1.3.10 Again using the rubber bulb per the instructions in Sections 11.1.3.4 and 11.1.3.5, rinse and drain stalagmometer twice with isopropyl alcohol and allow the stalagmometer to dry completely.

11.2 * * *

* * * * *

11.2.2 If a measurement of the surface tension of the solution is above the 40 dynes per centimeter limit when measured using a stalagmometer, above 33 dynes per centimeter when measured using a tensiometer, or above an alternate surface tension limit established during the performance test, the time interval shall revert back to the original monitoring schedule of once every 4 hours. A subsequent decrease in frequency would then be allowed according to Section 11.2.1.

* * * * *

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Part III

Environmental Protection Agency

40 CFR Part 63

National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2008–0334; FRL–9725–9]

RIN 2060–AQ89

National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; lift stay of final rule.

SUMMARY: On January 30, 2012, the EPA proposed revisions to several provisions of the final National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources. The proposed revisions were made, in part, in response to a petition for reconsideration received by the Administrator following the promulgation of the October 29, 2009, final rule (''2009 final rule''). In this action, the EPA is finalizing those amendments, lifting the stay of the title V permit requirement issued on March 14, 2011, and lifting the stay of the final rule issued on October 25, 2012. In addition, this final action includes revisions to the EPA's approach for addressing malfunctions and standards applicable during startup and shutdown periods. This final action also includes amendments and technical corrections to the final rule to clarify applicability and compliance issues raised by stakeholders subject to the 2009 final rule. The revisions to the final rule do not reduce the level of environmental protection or emissions control on sources regulated by this rule but provide flexibility and clarity to improve implementation. This action also extends the compliance date for existing sources and the EPA's final response to all issues raised in the petition for reconsideration.

DATES: The stay of subpart VVVVVV and the stay of paragraph (e) of 40 CFR 63.11494 are lifted as of December 21, 2012. This final rule is effective on December 21, 2012.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2008–0334. All documents in the docket are listed in the *www.regulations.gov index.* Although listed in the index, some information is not publicly available, *e.g.,* confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in www.regulations.gov or in hard copy at the EPA Docket Center, EPA West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Nick Parsons, 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) 541–5372; fax number: (919) 541–0246; email address: *parsons.nick@epa.gov.*

SUPPLEMENTARY INFORMATION:

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

CAA Clean Air Act
CEMS Continuous Emission Monitoring System
CFR Code of Federal Regulations
CMAS Chemical Manufacturing Area Source
CMPU Chemical Manufacturing Process Unit
COMS Continuous Opacity Monitoring System
CPMS Continuous Parameter Monitoring System
EPA Environmental Protection Agency
FESOP Federally Enforceable State Operating Permit
GACT Generally Available Control Technology
HAP Hazardous Air Pollutants
HON National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry
ICR Information Collection Request
lb/yr Pounds Per Year
MACT Maximum Achievable Control Technology
MON National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing
MSDS Material Safety Data Sheet
NESHAP National Emissions Standards for Hazardous Air Pollutants
NOCS Notice of Compliance Status
NTTAA National Technology Transfer and Advancement Act
OECA Office of Enforcement and Compliance Assurance
OMB Office of Management and Budget
ppmv Parts Per Million by Volume
RCRA Resource Conservation and Recovery Act
SARU Sulfuric Acid Regeneration Unit
SSM Startup, Shutdown and Malfunction
tpy Tons Per Year
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
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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A red-line version of the regulatory language that incorporates the changes in this action is available in the docket.

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

The EPA issued the NESHAP for the nine chemical manufacturing area source categories (40 CFR part 63, subpart VVVVVV) on October 29, 2009 (74 FR 56008). Pursuant to CAA section 307(d)(7)(B), the EPA received a petition for reconsideration on February 12, 2010. The petitioners requested that the EPA reconsider six provisions in the final rule. In response to this petition, the EPA proposed revisions to several provisions of the final rule on January 30, 2012 (77 FR 4522).

This final action addresses the public comments on the proposal and finalizes amendments to subpart VVVVVV. The amendments relate to issues raised in the petition for reconsideration and also include technical corrections that clarify applicability and compliance issues of the final rule. This action also lifts the stay of the title V permit requirement that was issued on March 14, 2011 (76 FR 13514) and the stay of the final rule that was issued on October 25, 2012 (77 FR 65135). This action also provides an extension of the compliance date for existing sources.

2. Summary of Major Provisions

The revised final rule lifts the stay on the title V permitting requirement and requires that certain chemical manufacturing synthetic area sources that installed controls obtain a title V permit. The EPA continues to believe that the additional protections provided by a title V permit are warranted for the sources subject to title V pursuant to this rule for the reasons stated in the rulemaking record. See 74 FR 56013–56014, 56034–56039 (October 29, 2009); 77 FR 4525–4527 (January 30, 2012).

The EPA is also finalizing several revisions to the final rule to improve clarity and provide facilities with greater flexibility. The leak inspection requirements are revised such that facilities conduct quarterly sensory inspections instead of "direct and proximal (thorough)" inspections, and that leak inspections may be conducted while equipment is in VOC service instead of in organic HAP service. The final rule also allows facilities to remove the required cover or lid on a process vessel when access is required during manual operations. Several definitions, including "in organic HAP service," "in metal HAP service," "metal HAP process vent" and "family of materials" are clarified and/or revised in the final rule. The EPA is also finalizing several technical corrections. Finally, the EPA is extending the compliance date for existing sources until March 21, 2013.

3. Costs and Emissions Reductions

The costs and emissions reductions associated with this rule have not changed from the October 29, 2009, final rule. Table 1 below summarizes the costs and emissions reductions of 40 CFR part 63, subpart VVVVVV. See section VI of the preamble to the October 29, 2009 final rule (74 FR 56039–56040) for further discussion of the costs and impacts.

TABLE 1—SUMMARY OF THE COSTS AND EMISSIONS REDUCTIONS OF 40 CFR PART 63, SUBPART VVVVVV

Requirement	Capital costs ($)	Annualized costs ($/yr)	Emissions reductions (tpy)
Batch process vents	$390,000	$370,000	<43
Continuous process vents	170,000	85,000	<29
Metal HAP process vents	690,000	1,700,000	41
Storage tanks	85,000	15,000	5
Heat exchange systems	640,000	280,000	79
Transfer operations	75,000	10,000	1
Wastewater systems	210,000	79,000	51
Management practices	540,000	685,000	N/A
Total	2,800,000	3,200,000	248

B. Does this action apply to me?

The regulated categories and entities potentially affected by this action include:

Industry category	NAICS code [1]	Examples of regulated entities
Chemical Manufacturing	325	Chemical manufacturing area sources that use as feedstock, generate as by-product or produce as product, any of the hazardous air pollutants (HAP) subject to this subpart except for: (1) Processes classified in NAICS Code 325222, 325314 or 325413; (2) processes subject to standards for other listed area source categories [2] in NAICS Code 325; (3) certain fabricating operations; (4) manufacture of photographic film, paper and plate where material is coated or contains chemicals (but the manufacture of the photographic chemicals is regulated); and (5) manufacture of radioactive elements or isotopes, radium chloride, radium luminous compounds, strontium and uranium.

[1] North American Industry Classification System.
[2] The source categories in NAICS Code 325 for which other area source standards apply are: Acrylic Fibers/Modacrylic Fibers Production, Chemical Preparation, Carbon Black, Chemical Manufacturing: Chromium Compounds, Lead Oxide Production, Polyvinyl Chloride and Copolymers Production, Paint and Allied Coatings and Mercury Cell Chlor-Alkali Manufacturing.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this reconsideration action. To determine whether your facility may be affected by this final rule, you should examine the applicability criteria in 40 CFR 63.11494 of subpart VVVVVV (National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources). If you have any questions regarding the applicability of the final rule to a particular entity, consult either the air permit authority for the entity or your EPA regional representative, as listed in 40 CFR 63.13.

C. How do I obtain a copy of this document and other related information?

Docket. The docket number for this action and the final rule (40 CFR part 63, subpart VVVVVV) is Docket ID No. EPA–HQ–OAR–2008–0334.

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

D. 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 United States Court of Appeals for the District of Columbia Circuit by February 19, 2013. 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 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 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 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 listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background Information

Section 112(d) of the CAA requires the EPA to establish national emission standards for hazardous air pollutants (NESHAP) for both major and area sources of HAP that are listed for regulation under CAA section 112(c). A major source is any stationary source that 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 stationary source that is not a major source.

On October 29, 2009 (74 FR 56008), the EPA issued the NESHAP for the nine chemical manufacturing area source (CMAS) categories that were listed pursuant to CAA sections 112(c)(3) and 112(k)(3)(B). The nine area source categories are Agricultural Chemicals and Pesticides Manufacturing, Cyclic Crude and Intermediate Production, Industrial Inorganic Chemical Manufacturing, Industrial Organic Chemical Manufacturing, Inorganic Pigments Manufacturing, Miscellaneous Organic Chemical Manufacturing, Plastic Materials and Resins Manufacturing, Pharmaceutical Production and Synthetic Rubber Manufacturing.

Section 112(k)(3)(B) of the CAA directs the EPA to identify at least 30 HAP that, as a result of emissions from area sources, pose the greatest threat to public health in the largest number of urban areas. The EPA implemented this provision in 1999 in the Integrated Urban Air Toxics Strategy (64 FR 38715, July 19, 1999) (Strategy). Specifically, in the Strategy, the 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 the EPA to list sufficient categories or subcategories of area sources to ensure that area sources representing 90 percent of the area source emissions of the 30 urban HAP are subject to regulation. The EPA completed this requirement in 2011 (76 FR 15308, March 21, 2011). The nine CMAS categories were listed to satisfy this requirement for 15 of the 30 urban HAP.[1] Pursuant to CAA section 112(d)(5), the NESHAP reflect generally available control technologies or management practices (GACT). The NESHAP apply to each chemical manufacturing process unit (CMPU) that uses, generates or produces any of the 15 urban HAP for which the area source categories were listed (collectively

[1] The 15 urban HAP for which the chemical manufacturing area source categories were listed under CAA section 112(c) are identified in table 1 of the final rule.

''chemical manufacturing urban HAP'' or ''Table 1 HAP'').

On February 12, 2010, following promulgation of the 2009 final rule, the EPA received a petition for reconsideration from the American Chemistry Council and the Society of Chemical Manufacturers & Affiliates (''Petitioners''). A copy of this petition is provided in the docket (see Docket Item No. EPA–HQ–OAR–2008–0334–0098). Petitioners, pursuant to CAA section 307(d)(7)(B), requested that the EPA reconsider six provisions in the rules: (1) The requirement that major sources that installed air pollution controls after 1990, and, as a result, became area sources, obtain a title V permit; (2) the requirement that sources subject to the final rule and any overlapping provision in another rule comply with each provision independently, or with the most stringent requirements of each rule; (3) the requirement that leak inspections include direct and proximal (thorough) inspection of all areas of potential leak within the CMPU; (4) the requirement that process vessels in HAP service be equipped with a cover or lid that must be in place at all times when the vessel contains HAP, except for material addition and sampling; (5) the requirement to conduct leak inspections while the equipment is in HAP service; and (6) the requirement that a CMPU include all equipment and processes used to produce a ''family of materials.'' [2] The arguments in support of these requests are provided in the petition and in the preamble to the reconsideration proposed rule revisions (77 FR 4525–4530, January 30, 2012). Petitioners also requested that the EPA stay the effectiveness of these provisions of the rule to save many facilities from needlessly having to file the initial notifications required by the final rule.

On June 15, 2010, the EPA sent a letter to the Petitioners informing them that the EPA was granting the request for reconsideration on at least one of the issues raised in the petition, and that the agency would identify the specific issue or issues for which it was granting reconsideration in the reconsideration notice that would be published in the **Federal Register**. The letter also indicated that the EPA considered the request for a stay to be moot because the due date for initial notifications had already passed.

On January 30, 2012, the EPA published proposed rule revisions that included six provisions for which reconsideration was requested. Specifically, the EPA: (1) Proposed to narrow the requirement for sources to obtain a title V permit to only those synthetic area sources that installed a federally-enforceable control device on an affected CMPU; (2) sought comment on the overlapping provisions requirement; (3) proposed to remove the requirement to conduct direct and proximal (thorough) leak inspections; (4) proposed to allow sources to remove the cover or lid on a process vessel when manual access is necessary; (5) sought comment on allowing leak inspections to be conducted when equipment is in volatile organic compound (VOC) service; and (6) proposed to clarify the family of materials concept. In addition, the EPA also proposed clarifying revisions to the requirements for metal HAP process vents, the addition of the affirmative defense provisions and numerous technical corrections.

On October 25, 2012, the EPA published a 60-day stay of the final CMAS rule (77 FR 65135). The compliance date for the final CMAS rule was October 29, 2012, and it was the EPA's expectation that the reconsideration would be finalized in advance of that date. However, the EPA was still in the process of finalizing the reconsideration action. For that reason, a short stay of the final rule was appropriate to allow the EPA the time necessary to complete the reconsideration action.

III. Summary of Final Rule Revisions

A. Applicability of the Family of Materials Concept

The final rule revises the definition of ''family of materials'' in 40 CFR 63.11502(a) by removing the definition that was incorporated by reference to the Miscellaneous Organic Chemical Manufacturing NESHAP (MON) and replacing it with a definition in 40 CFR 63.11502(b) specific to the CMAS rule. The definition clarifies that the family of materials concept applies only to those products whose production involves emission of the same Table 1 HAP.

B. Title V Permitting Requirements

The revised final rule requires synthetic area sources that installed a federally-enforceable control device on at least one affected CMPU to obtain a title V permit. The final rule lifts the stay on the title V permitting requirement (76 FR 13514, March 14, 2011) and requires such sources to submit their title V permit application by December 21, 2013 or on such earlier date as the title V permitting authority requires.

C. Requirements When Other Rules Overlap With the Final Rule

The revised final rule requires that facilities comply with the most stringent requirements when there are overlapping provisions in the CMAS rule and other NESHAP. Sources are required to determine which of the overlapping requirements applicable to the source are more stringent.

D. Requirement To Conduct Direct and Proximal Leak Inspections

The revised final rule removes the requirement in 40 CFR 63.11495(a)(3) that facilities conduct a ''direct and proximal (thorough)'' leak inspection, and instead requires that facilities conduct quarterly sensory inspections of all equipment and process vessels, provided that these methods are capable of detecting leaks within the CMPU (*i.e.,* the inspector is within sufficient proximity to the equipment that leaky equipment can be detected by sight, sound or smell). The revised final rule also allows affected facilities to conduct leak inspections of equipment in VOC service instead of in organic HAP service, provided that leaks can be detected while in VOC service. A CMPU that contains metal HAP as particulate must conduct leak inspections while the equipment is in metal HAP service.

E. Requirement for Covers or Lids on Process Vessels

The final rule requires in 40 CFR 63.11495(a)(1) that a cover or lid must be in place and closed at all times when a process vessel is in organic HAP service or in metal HAP service, except when access is required during manual operations such as material addition, removal, inspection, sampling and cleaning. Process vessels containing metal HAP that are in a liquid solution or other form that will not result in particulate emissions of metal HAP (*e.g.,* metal HAP that is in ingot, paste, slurry or moist pellet form or other form) are not subject to this requirement.

The definitions of ''in organic HAP service'' and ''in metal HAP service'' in 40 CFR 63.11502(b) have been revised to state that a process vessel is no longer considered to be in organic HAP service or in metal HAP service once it has been emptied to the extent practicable and any cleaning has been completed.

[2] The petition also requested that the EPA take comment on three additional issues: (1) A *de minimis* exemption for all sources; (2) a revision of the definition of laboratory analysis unit to include commercial development activities; and (3) a pollution prevention alternative. The EPA did not seek comment on these issues in reconsideration as explained below in section VI of this preamble.

F. Requirement To Conduct Leak Inspections When Equipment Is in HAP Service

The final rule requires in 40 CFR 63.11495(a)(3) that leak inspections be conducted while the subject CMPU is operating in organic HAP service or in metal HAP service. This provision also allows CMPU that do not contain metal HAP as particulate to conduct leak inspections when the subject CMPU is in VOC service, provided that leaks can be detected while in VOC service. A CMPU that contains metal HAP as particulate must conduct leak inspections while the equipment is in metal HAP service.

G. Requirements During Periods of Startup, Shutdown and Malfunction

The EPA is adding to the final rule an affirmative defense to civil penalties for violations of emission standards that are caused by malfunctions. During the comment period of the October 6, 2008, proposed rule ("2008 proposal"), the United States Court of Appeals for the District of Columbia Circuit vacated 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 (D.C. Cir. 2008), cert. denied, 130 S. Ct. 1735 (U.S. 2010). Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), that are part of a regulation, commonly referred to as the "General Provisions Rule," that the EPA promulgated under section 112 of the CAA. When incorporated into CAA section 112(d) regulations for specific source categories, the exemption in these two provisions exempts sources from the requirement to comply with otherwise applicable CAA section 112(d) emission standards during periods of SSM.

The 2008 proposal contained references to the vacated provisions. Because the provisions were vacated, we removed the references in the 2009 final rule, and, consistent with *Sierra Club* v. *EPA,* established standards that applied at all times. In the vacated provisions' place, we included alternative standards for startup and shutdown periods for continuous process vents. Table 3 to 40 CFR part 63, subpart VVVVVV. For batch process vents, we determined that startup and shutdown periods were already accounted for in the existing standard and we determined that the remaining equipment did not have periods of startup and shutdown. See 74 FR 56013, October 29, 2009. We declined to establish a different standard for malfunctions, as suggested by commenters. See 74 FR 56033, October 29, 2009.

Further, as explained in the preamble to the 2009 final rule (74 FR 56033, October 29, 2009), 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. 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. 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."

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 categories 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(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 a violation of the relevant emission standard. (See, *e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown* (September 20, 1999); *Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions* (February 15, 1983)).

The EPA is therefore adding to the final rule an affirmative defense to civil penalties for violations of emission standards that are caused by malfunctions, consistent with other recent actions by the EPA (*e.g.,* the NESHAP for Group I Polymers and Resins and the NESHAP for Pharmaceuticals Production. 76 FR 22566 (April 21, 2011)). See 40 CFR 63.11502 (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 40 CFR 63.11501(e). See 40 CFR 22.24. The criteria ensure that the affirmative defense is available only where the event that causes a violation of the emission standard meets the narrow definition of malfunction in 40 CFR 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 the violations ''[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 CAA section 63.11501(e), and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that ''[r]epairs were made as expeditiously as possible when a violation occurred* * *'' and that ''[a]ll possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health* * *.'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense, and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR 22.77).

The EPA included an affirmative defense in this 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 violated under circumstances beyond the control of the source. The EPA must establish emission standards that ''limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.'' 42 U.S.C. 7602(k) (defining ''emission limitation and emission standard''). See, generally, *Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (D.C. Cir. 2008). Thus, the EPA is required to ensure that section 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. See generally, *Luminant Generation Co. LLC* v. *United States EPA,* 2012 U.S. App. LEXIS 21223 (5th Cir. Oct. 12, 2012) (upholding EPA's approval of affirmative defense provisions in a CAA State Implementation Plan). 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 call into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for violations that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating ''upsets beyond the control of the permit holder.'' *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). See also, *Mont. Sulphur & Chem. Co.* v. *EPA,* 2012 U.S. App. LEXIS 1056 (January 19, 2012) (rejecting industry argument that reliance on the affirmative defense was not adequate). But see, *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission 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.

In addition to the affirmative defense provisions described above, we are also making several changes throughout the rule and in Table 9 (the table that specifies applicability of General Provisions to subpart VVVVVV of 40 CFR part 63) to specify applicable requirements during periods of startup and shutdown and periods of malfunction. For example, we are adding new paragraphs in 40 CFR 63.11501(c)(1)(vii) and (viii) that would require records of the occurrence and duration of malfunctions, as well as records of actions taken to minimize emissions during these periods and to fix malfunctioning equipment. We are also adding a paragraph in 40 CFR 63.11501(d)(8) that would require reporting of information related to each malfunction. Table 9 in the final rule states that 63.6(e)(1)(i) does not apply to subpart VVVVVV. We are also adding a new paragraph in 40 CFR 63.11495(d) that specifies the general duty to minimize emissions applies at all times. In addition to the changes in the text of the rule, we are revising the entries for 40 CFR 63.6(e)(1)(i), 63.10(b)(2) and 63.10(d)(5) to reference the new paragraphs in 40 CFR 63.11495(d), 63.11501(c) and 63.11501(d). Finally, we are revising Table 9 to state that the performance testing requirements in 40 CFR 63.7(e)(1) do not apply. The comments to Table 9 for that provision identify the location of the applicable performance testing requirements for sources subject to the CMAS rule.

H. Requirements for Metal HAP Process Vents

The revised final rule defines a ''metal HAP process vent'' to include only those streams which contain at least 50 parts per million by volume (ppmv) metal HAP. Process vents from CMPU that only contain metal HAP in a liquid solution or other form that will not result in particulate emissions of metal HAP (*e.g.,* metal HAP that is in ingot, paste, slurry or moist pellet form or other form) are not required to comply with the metal HAP process vent requirements.

I. Extension of the Compliance Date

The EPA is extending the compliance date for existing sources until March 21, 2013.

J. Technical Corrections

The final rule provides several technical corrections. These

amendments are being finalized to correct inaccuracies and oversights that were previously promulgated. These changes are described in Table 2 of this preamble. Several of these issues were identified through the public comments and the EPA identified others.

TABLE 2—MISCELLANEOUS TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART VVVVVV

Section of subpart VVVVVV	Description of correction
40 CFR 63.11494(a)(3)	We are finalizing several changes to this paragraph. First, we are clarifying that the 0.1-percent and 1.0-percent concentration thresholds are on a mass basis of the individual Table 1 HAP. Second, we are clarifying that all Table 1 HAP, except for quinoline, manganese, and trivalent chromium compounds, are considered carcinogenic, probably carcinogenic or possibly carcinogenic. Therefore, the concentration threshold of 1.0 weight percent applies only to quinoline, manganese, and trivalent chromium compounds, and the threshold of 0.1 weight percent applies to all other Table 1 HAP. Third, we are clarifying applicability of CMPU that generate a Table 1 HAP byproduct. If Table 1 HAP are generated as a byproduct, the changes clarify that the CMPU is subject to the rule if the concentration of the Table 1 HAP in any liquid stream in the CMPU exceeds the same thresholds that apply to feedstocks. Specifically, if quinoline is generated as a byproduct, then the CMPU is subject if the quinoline concentration in any liquid stream in the CMPU exceeds 1.0 percent by weight. Similarly, if hydrazine or any other organic Table 1 HAP is generated as a byproduct, then the process is subject if the individual concentration of these compounds in any liquid stream is greater than 0.1 percent by weight. In addition, we are clarifying that if hydrazine or any other organic Table 1 HAP is generated as a byproduct, then the process is subject if the individual concentration of these compounds in any batch process vent or continuous process vent is greater than 0.1 percent by weight. Finally, we are consolidating paragraphs (a)(1) and (3) to eliminate redundancy.
40 CFR 63.11494(c)(1)(vii)	We are adding a new paragraph that lists lead oxide production at lead acid battery manufacturing facilities in those operations for which this subpart does not apply. These sources are covered by 40 CFR part 63, subpart PPPPPP—NESHAP for Lead Acid Battery Manufacturing Area Sources.
40 CFR 63.11494(d)	We are clarifying that a CMPU using only Table 1 metal HAP is not subject to any requirements for wastewater systems or heat exchange systems. Only organic HAP are subject to wastewater and heat exchange system requirements.
40 CFR 63.11495(a)(3)	We are splitting this section into an introductory section with five subsections. One sentence that contains two concepts has also been split into two separate sentences. The requirements, however, have not changed.
40 CFR 63.11496(c)	We are adding an example of emission contributions to subtract when determining the TRE index value of individual streams before they are combined.
40 CFR 63.11496(d)	We are revising the title of this paragraph and clarifying that the mass emission rate of halogen atoms must be calculated in accordance with § 63.115(d)(2)(v), or alternatively you may designate an emission stream as halogenated.
40 CFR 63.11496(e)	We are adding a new paragraph that clarifies that CEMS requirements and data reduction requirements for CEMS specified in § 63.2450(j) apply.
40 CFR 63.11496(f)(3)(i)(C)	We are editing this paragraph to add the acronym "CMS."
40 CFR 63.11496(f)(3)(ii)	We are editing the first sentence in this paragraph to remove the unnecessary word "report."
40 CFR 63.11496(f)(3)(ii)	We are clarifying that if a source elects to conduct an engineering assessment to demonstrate initial compliance with the standards for metal HAP process vents, then the design evaluation must be conducted at representative operating conditions for the CMPU.
40 CFR 63.11494(g)(2)	We are clarifying that you may elect to conduct a design evaluation instead of a performance test to determine initial compliance with an outlet concentration emission limit.
40 CFR 63.11494(g)(4)(i)	We are clarifying that you may measure caustic strength of the scrubber effluent for any halogen scrubber within a CMPU subject to this rule.
40 CFR 63.11494(g)(5)	We are clarifying that 40 CFR 63.996(c)(2)(ii) and 63.998(c)(1)(ii)(E) do not apply for the purposes of this subpart.
40 CFR 63.11494(g)(8)	We are adding a new paragraph that clarifies when the initial demonstration requirements for process condensers applies.
40 CFR 63.11497	We are adding a paragraph to this section clarifying that the halogenated vent stream provisions also apply to affected storage tanks.
40 CFR 63.11498(a)(2), 63.11502(b), and Table 6.	We are adding a definition of "hazardous waste treatment" in 40 CFR 63.11502(b) to mean treatment in either (1) a RCRA-permitted incinerator, process heater, boiler, or underground injection well, or (2) an incinerator, process heater, or boiler complying with 40 CFR part 63, subpart EEE. We are also adding corresponding changes to Table 6 to subpart VVVVVV. Specifically, for each wastewater stream, Item 1.a would require either wastewater treatment or hazardous waste treatment. In addition, Item 2.b would be edited to use the new term "hazardous waste treatment" and to allow for hard piping of wastewater streams to a point of transfer to onsite hazardous waste treatment. The changes to Item 1.a also make it clear that the treatment conducted to meet Item 2.b would satisfy the requirements of Item 1.a.
40 CFR 63.11500(a) and Table 5	We are adding a paragraph to 40 CFR 63.11500(a) to clarify that that offsite reloading and cleaning facilities that are subject to 40 CFR 1253(f) and comply with the monitoring, recordkeeping, and reporting requirements in any other subpart of part 63 are considered to be in compliance with the monitoring, recordkeeping, and reporting requirements of 40 CFR 63.1253(f)(7)(ii) or (iii). We are also adding corresponding changes to Table 5 to subpart VVVVVV to clarify which requirements apply to owners or operators of offsite cleaning or reloading facilities.
40 CFR 63.11501(b)	We are revising this paragraph to allow sources to submit their notice of compliance status (NOCS) reports no later than 60 days after the applicable compliance date.
40 CFR 63.11501(c)(4)(i)	We are replacing the incorrect word "dimension" with the correct word "dimensions."

TABLE 2—MISCELLANEOUS TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART VVVVVV—Continued

Section of subpart VVVVVV	Description of correction
40 CFR 63.11502(a)	We are inserting references to the definitions of the terms "batch operation," "continuous operation," and "isolated intermediate" in 40 CFR 63.2550 of the MON. We are also inserting a reference to the definition of "control device" in 40 CFR 63.111 of the Hazardous Organic Chemical Manufacturing NESHAP (HON).
40 CFR 63.11502(b)	We are modifying the definition of "batch process vent" to clarify that vents from batch operations are considered to be batch process vents.
40 CFR 63.11502(b)	We are adding a definition for the term "engineering assessment" consistent with 40 CFR 63.1257(d)(2)(ii), but which has been revised to include the appropriate references for this rule.
40 CFR 63.11502(b)	We are adding a definition for the term "point of determination" consistent with 40 CFR 63.111 of the HON, but which has been revised to include the appropriate references for this rule.
40 CFR 63.11502(b)	We are modifying the definition of "product" to remove "isolated intermediates" from the list of materials that are not considered products.
40 CFR 63.11502(b)	We are adding a definition for the term "uncontrolled emissions" that reads: "Uncontrolled emissions means organic HAP or metal HAP process vent emissions, as applicable, at the outlet of the last recovery device, if any, and prior to any control device. In the absence of both recovery devices and control devices, uncontrolled emissions are the emissions discharged to the atmosphere."
Table 3	We are replacing the reference to 40 CFR 63.982(c)(2) in item 1.a with the correct reference to 40 CFR 63.982(c).
Table 3	We are adding an item to this table for continuous process vents with a TRE >1.0 but ≤4.0. This item clarifies that these continuous process vents are required to comply with 40 CFR 63.982(e) if a recovery device is used to maintain a TRE >1.0 but ≤4.0.
Table 5	We are replacing the reference to 40 CFR 63.982(c)(1) in item 1.b with the correct reference to 40 CFR 63.982(c). We are also removing the requirement in item 1.b.ii to comply with the inspection requirements in 40 CFR 63.11495 for closed vent systems.
Table 8	We are revising item 1.a.i to clarify that the reference to monthly monitoring for the first 6 months in 40 CFR 63.104(b)(1) does not apply.
Table 9	We are revising the entry to 40 CFR 63.8(c)(4) to state that this paragraph does apply, but only for CEMS. The requirements for CPMS are contained in 40 CFR part 63, subpart SS, and requirements for COMS do not apply.
Table 9	We are revising the entry for 40 CFR 63.8(g)(5) to clarify that the data reduction requirements for CEMS are specified in 40 CFR 63.2450(j) and that CPMS requirements are specified in 40 CFR part 63, subpart SS.
Table 9	We are adding an entry for 40 CFR 63.9(i) to state that this paragraph applies to subpart VVVVVV.

IV. Summary of Major Changes Since Proposal

The EPA received 19 public comment letters on the proposed revisions to the CMAS final rule. In addition, the EPA received six comments and sets of materials from industry representatives following the close of the comment period. After consideration of these comments, the EPA is making several changes to the final rule. Following are the major changes to the standards since the proposal. The rationale for these and other significant changes can be found in this section, in section V of this preamble, and in the National Emission Standards for Hazardous Air Pollutant Emissions for Chemical Manufacturing Area Source—Reconsideration: Summary of Public Comments and Responses, in the CMAS rule docket (EPA–HQ–OAR–2008–0334).

A. Title V Permitting Requirements

In the proposed rule revisions, we proposed to narrow the applicability of title V permitting requirements for certain synthetic area sources subject to the final rule. Specifically, under the proposal, only those sources that installed a federally-enforceable control device on an affected CMPU in order to become an area source would be subject to the requirement to obtain a title V permit. The EPA received public comments on this issue from industry representatives and two states during the public comment period. Public commenters were generally opposed to the EPA requiring any affected source to obtain a title V permit. The commenters were concerned that the burden of obtaining a title V permit was not warranted given the level of public participation already required by, and other requirements associated with, a Federally Enforceable State Operating Permit (FESOP) that sources with a federally-enforceable control device must already obtain. However, commenters stated that if the EPA should choose to require certain sources to obtain a title V permit, then they supported limiting the requirement to apply to only those sources that installed a federally-enforceable control device on an affected CMPU.

As a preliminary matter, we note that section 502(a) of the CAA requires all area sources subject to CAA section 112 standards to obtain a title V permit unless the EPA makes a finding that title V is impracticable, infeasible or unnecessarily burdensome. The EPA did not exempt CMAS synthetic area sources that installed controls to limit HAP emissions because we believe that the limited burden resulting from the applicability of title V to these area sources is outweighed by the benefits of the title V permit. The EPA also continues to maintain that "while there is some burden on the affected facilities, we think that the burden is not significant because these facilities are generally larger and more sophisticated than the natural area sources and sources that took operational limits to become area sources." 74 FR 56014.

In the final rule revisions, we have made slight revisions to the proposed changes to the title V permit requirement to further clarify the applicability of title V to CMAS sources. Specifically, we have revised the rule to make clear that the installation of a federally-enforceable air pollution control device on an affected CMPU triggers the title V permit requirement for any synthetic area source subject to the final rule if the air pollution controls installed on the affected CMPU are required to maintain the source's emissions at area source levels. The EPA continues to believe that the additional protections provided by a title V permit

are warranted for CMAS synthetic area sources that installed controls because they are generally larger, more sophisticated and have higher HAP emissions before control than natural area sources and synthetic area sources that took operational limits. See 74 FR 56013–56014, 56034–56039 (October 29, 2009); 77 FR 4525–4527 (January 30, 2012).

If a synthetic area source is subject to the CMAS rule and it has installed a federally-enforceable control device on an affected CMPU in order to become an area source, it is subject to title V and it must obtain a permit. Under 40 CFR 70.3(c)(2), for any non-major source subject to title V, the permitting authority must include in the permit all applicable requirements that apply to emissions units (i.e., the CMPU) that trigger applicability of title V. 40 CFR 70.3(c)(2); see also 40 CFR 70.2 (defining ''applicable requirement''). Thus, the state title V permitting authority may require a source subject to title V pursuant to the CMAS rule to include in the title V permit only the applicable requirements that apply to the CMPU(s) that cause the source to be subject to title V.

Additionally, based on the comments submitted by industry, we appreciate industry's concern that, due to the nature of chemical manufacturing, specifically specialty and batch chemical manufacturing, the industry needs operational flexibility and that some types of operational changes involving the affected CMPU could be subject to frequent title V revisions. There are several flexible permitting techniques available to sources through the title V permitting program, such as Alternative Operating Scenarios and Approved Replicable Methodologies. See 74 FR 51418 (October 6, 2009). We therefore encourage sources to consider the viability of establishing flexibility upfront in their respective title V permits as a way to avoid permit revisions, without sacrificing compliance assurance or operational flexibility.

B. Requirement for Covers or Lids on Process Vessels

In the proposed rule revisions, we requested comment on whether a change was needed for the definition of ''in metal HAP service'' to make it consistent with the proposed revisions to the definition of ''in organic HAP service.'' Public commenters were generally in favor of these proposed revisions.

In the final rule revisions, we have revised the definition of ''in metal HAP service'' to state that, consistent with the revised definition of ''in organic HAP service,'' a process vessel is no longer in metal HAP service after the vessel has been emptied to the extent practicable (*i.e.,* a vessel with liquid left on process vessel walls or as bottom clingage, but not in pools, due to floor irregularity, is considered completely empty) and any cleaning has been completed. We have also revised the requirement that a cover or lid must be in place and closed at all times when a process vessel is in organic HAP service or in metal HAP service to not apply for CMPU using only metal HAP that are in a liquid solution or other form that the source determines will not result in particulate emissions of metal HAP (*e.g.,* metal HAP that is in ingot, paste, slurry or moist pellet form or other form).

C. Requirement To Conduct Leak Inspections When Equipment Is in HAP Service

We solicited comment on whether to permit leak inspections to be conducted when equipment was in VOC service, rather than just when it was in organic HAP service or in metal HAP service. Public commenters were generally in favor of allowing leak inspections to be conducted while equipment was in VOC service.

In the final rule revisions, we are allowing facilities to conduct leak inspections of equipment in VOC service, provided that leaks can be detected while in VOC service. A CMPU that contains metal HAP as particulate must conduct leak inspections while the equipment is in metal HAP service. We have also added a corresponding definition of ''in VOC service'' to mean that a process vessel or piece of equipment either contains or contacts a fluid that contains VOC.

D. Requirements for Metal HAP Process Vents

In the proposed rule revisions, we solicited comment on whether the definition of ''metal HAP process vent'' was applicable to all types of equipment from which metal HAP are emitted. The original rule defined a metal HAP process vent as ''the point of discharge to the atmosphere (or inlet to a control device, if any) of a metal HAP-containing gas stream from any CMPU at an affected source,'' regardless of the concentration of metal HAP in the stream. Public commenters were generally in favor of defining a metal HAP process vent as containing at least 50 ppmv metal HAP, consistent with the MON.

In the final rule revisions, we have revised the definition of ''metal HAP process vent'' to include only those streams which contain at least 50 ppmv metal HAP. We have also revised the final rule to state that process vents from CMPU that only contain metal HAP in a liquid solution or other form that will not result in particulate emissions of metal HAP (*e.g.,* metal HAP that is in ingot, paste, slurry or moist pellet form or other form) are not required to comply with the metal HAP process vent requirements.

E. Extension of the Compliance Date

In the proposed rule revisions, we did not propose to revise the compliance date for the final rule, which was October 29, 2012. Under CAA section 112, the compliance date may be no more than 3 years after the effective date of the final rule, which for the CMAS rule was October 29, 2009. Public commenters were concerned that due to the expected short period of time between the promulgation of the final rule amendments and the existing October 29, 2012, compliance date, there would not be sufficient time for facilities to review the revised rule requirements and certify compliance by the compliance date. The commenters were particularly concerned with determining compliance because the proposed changes to the family of materials concept may affect applicability of the final standards to CMPU located at sources subject to the CMAS rule. It was the EPA's expectation that the reconsideration would be finalized in advance of October 29, 2012, compliance date. However, the EPA was still in the process of finalizing the reconsideration action, and on October 25, 2012, the EPA published a 60-day stay of the final CMAS rule (77 FR 65135).

In the final rule, the EPA is extending the compliance date for existing sources until March 21, 2013. We agree that existing sources should have additional time to evaluate applicability in light of the amendments to the rule since publication of the final reconsideration action is occurring so close to the existing source compliance date. We think this short extension will provide sources the necessary time to determine applicability and take the actions necessary to comply with the final rule. The EPA is not revising the compliance date for new sources.

F. Technical Corrections

In the proposed rule revisions, we proposed in 40 CFR 63.11494(a)(3) a technical correction that the concentration thresholds for applicability of Table 1 HAP present in feedstocks or any liquid streams (process or waste) were to be

determined on a collective Table 1 HAP basis. In addition, we also proposed to specify that a CMPU is subject to the CMAS rule if the collective concentration of Table 1 HAP exceeded 50 ppmv in any process vent stream. Public commenters were concerned that by revising the rule to determine applicability based on collective Table 1 HAP concentration and a 50 ppmv threshold, the applicability of the rule would be greatly expanded beyond its original scope.

In the final rule revisions, we have revised this language to clarify that the concentration thresholds for applicability of Table 1 HAP are to be determined on an individual Table 1 HAP concentration, rather than a collective concentration. In addition, we have also clarified that the 0.1 percent by weight threshold for Table 1 HAP present in liquid streams (process or waste) also applies to Table 1 HAP present in any continuous process or batch process vent, rather than the proposed 50 ppmv threshold.

We are not finalizing this proposed change because we did not fully consider the implications of the proposed change. We included the proposed change in the technical corrections section of the proposed rule on the belief that it was a technical change, but, in fact, the change, if finalized, would have had significant consequences. The proposed change would have likely lead to a considerable expansion of the applicability of the rule. In addition, sources would no longer have been able to determine applicability by reviewing their Material Safety Data Sheets (MSDS) as the 2009 final rule provides because the MSDS does not indicate the amount of emissions below the 0.1 percent threshold. This would mean that sources would have to go to considerable lengths at considerable cost in testing very low levels of HAP to even determine whether the final rule applies to their CMPUs, which is not what the EPA intended.

V. Summary of Comments and Responses

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 Pollutant Emissions for Chemical Manufacturing Area Source—Reconsideration: Summary of Public Comments and Responses, in the CMAS rule docket (EPA–HQ–OAR–2008–0334).

A. Title V Permitting Requirements

Comment: Eight commenters objected to the requirement that certain synthetic area sources subject to the CMAS rule be required to obtain a title V permit. The commenters stated that the requirement would be overly burdensome and that it would impose significant additional costs on facilities while achieving no additional environmental benefit or gains in compliance. The commenters estimate that it will cost a facility $25,000–$100,000 to obtain a title V permit.

In contrast, one commenter stated that the cost of obtaining a title V permit instead of a synthetic area source permit in their area is comparable due to associated permit fees for synthetic area source permits and emission fees for title V permits.

Response: The EPA disagrees with the commenters that the requirement to obtain a title V permit is overly burdensome and we maintain that title V is appropriate for the sources that will be subject to title V pursuant to this final rule. In the preamble to the final rule, we determined that "requiring additional public involvement and compliance assurance requirements through title V is important to ensure that these sources are maintaining their emissions at the area source level, and, while there is some burden on the affected facilities, we think that the burden is not significant because these facilities are generally larger and more sophisticated than the natural area sources and sources that took operational limits to become area sources." 74 FR 56014. The cost estimates provided by the commenters are very broad and the commenters do not provide any information to support the cost estimates that were provided; therefore, the EPA is unable to evaluate the validity of these estimates.

Comment: Three commenters expressed concern with the impacts that the title V program requirements might impose on a source subject to the CMAS rule. In particular, they expressed concern with the ability of batch operations that have the need for quick changes to their production processes to be able to make such changes rapidly and with the necessary permitting flexibility. The commenters stated that by requiring a title V permit, the facility will be required to apply for a permit modification every time they wanted to manufacture a new product, costing them both time and money and placing them at a competitive disadvantage.

Response: We appreciate that the commenters want to maintain operational flexibility, but title V permits can and do accommodate provisions that provide operational flexibility for batch processing (and other) operations. In fact, permitting authorities have been incorporating operational flexibility for batch processes into title V permits through a variety of mechanisms provided under existing rules. These flexibilities have eliminated the need to modify permits when new products are manufactured. For example, since 2003, a number of specialty chemical manufacturers, who use batch processing, are subject to title V permitting under the Miscellaneous Organic NESHAP (MON). To accommodate the need for frequent operational changes at these facilities, states have issued flexible operating permits that provide these sources with the ability to obtain approval in advance for a variety of alternative operating scenarios, categories of changes, plant-wide applicability limits, or other operating flexibilities that enable them to operate in the most effective way while still complying with the requirements of the title V program. As the CMAS rule notes, batch CMAS sources, like MON sources, can take advantage of similar flexibilities and set their continuous monitoring parameters based on their projected range of batch scenarios.

This type of flexibility has been effectively incorporated into title V permits to sources in the semiconductor industry for many years. Just like the specialty chemical manufacturing industry, the semiconductor industry operates in a rapidly changing environment, requiring flexibility to make quick changes without the need to go through permit modifications. Through the use of advance approvals and flexible permits, companies such as Intel have been able to operate in a quickly changing environment while complying with the requirements of the title V program. Intel currently introduces a new generation of semiconductor chips every 12 to 24 months, with each new product cycle supported by a major facility revamp. These operational changes are time sensitive to meet product release schedules from computer and electronics manufacturers and involve highly interdependent and sequenced steps. Intel also reported a need to make rapid (and sometimes iterative) process and equipment adjustments in production processes to improve yield, lower costs, reduce chemical usage, and otherwise improve operations. The

advance approved changes in Intel's flexible permit likely saved the plant hundreds of business days associated with making operational and process changes to ramp up production for new products, respond to market demands, and optimize production processes. Industry estimates of the opportunity costs of production downtime and time delays run as high as several million dollars in just a few days due to lost sales to computer makers and other factors. The estimated 150 to 200 changes per year, combined with the otherwise normally expected approval time frame of up to 60 days per change, indicate that there would likely have been significant delay under a conventional permitting approach. Intel has in the past cited its flexible air permit as a vital element enabling Intel to double employment during the permit term and to transfer and scale-up production of next generation computer chips at plants throughout the U.S., retaining and creating thousands of additional jobs.

The EPA is willing to work with companies and state permitting authorities to ensure they are aware of the flexibilities already available under the title V permitting program that address the concerns of the small number of CMAS synthetic area sources that must obtain a title V permit.

Comment: Four commenters stated that the process for obtaining a synthetic area source permit and the amount of information contained in it are very similar to those of a title V permit. Three of the commenters detailed the steps involved in obtaining each type of permit, as well as the information contained in each. The commenters also stated that both processes provide opportunity for public comment on the draft permit and that the facilities may be required to certify compliance annually. One of the commenters also provided general information on FESOPs and synthetic area source permits issued in Illinois and Ohio. Another commenter also provided general information on FESOP and synthetic area source permits for 11 states, including whether notice and comment is required and what additional oversight is conducted by the state. One commenter noted that FESOP programs must be approved through State Implementation Programs, which provide an opportunity for both the EPA and public comment. Another commenter stated that under the North Carolina Division of Air Quality's air permitting program, synthetic area sources are already subject to annual inspections similar to what title V requires. The commenter also stated that sources that have add-on controls typically have lower emissions than sources that have taken operational limits to become synthetic area sources.

Response: While the commenters provided broad, general information on the requirements of FESOPs as compared to title V permits, none of them provided specific examples of these permits for the EPA to evaluate and compare to title V permits. Without this specific information from each state (as the requirements for a FESOP vary by state), the EPA cannot conclude that FESOPs provide the same level of information as that of a title V permit. In addition, unlike FESOP programs, petitions to object to title V permits may be brought before the EPA. As the requirements for public participation for a FESOP vary by state, the EPA cannot be assured that all citizens in all states would be afforded the same level of public participation that a title V permit would provide.

In addition, title V requires a facility to include in the title V permit all applicable requirements that apply to CMAS affected units, not just the CMPU requirements that trigger applicability of title V, so that the public will be able to assess a source's compliance with all requirements that apply to CMAS affected units by reviewing the title V permit. The public is provided access to compliance demonstration information submitted to state permitting authorities and there is no indication in the comments that such information is available pursuant to state FESOP programs.

Furthermore, even though certain states, such as North Carolina, may require that a synthetic area source be subject to additional inspections, this requirement varies by state and only a title V permit would assure that these additional inspections are required for all CMAS synthetic area sources required to obtain a title V permit. Finally, we do not agree with the assertion that sources that install control devices necessarily have lower emissions than those that have taken operational limits to maintain area source status, as both types of synthetic area sources are subject to the same requirement to maintain emissions below 10 tpy of any single HAP or 25 tpy of any combination of HAP. It is the potential level of emissions from the synthetic area source absent controls or operational limits that we considered when comparing the two types of synthetic area sources. In the 2009 final rule and the reconsideration proposed rule revisions, we noted that one reason why we were not exempting synthetic area sources that installed controls from title V is because we believe the sources are "generally larger and more sophisticated" than natural area sources and the synthetic area sources that took operational limits. See 77 FR 4525; 74 FR 56014. We also stated that we believe the uncontrolled HAP emissions from synthetic area sources that installed controls are generally much higher than the natural area sources and synthetic area sources that took operational limits. *Id.* The commenters did not provide any information that causes us to question our conclusions.

Comment: Four commenters stated that requiring synthetic area sources that installed control devices to obtain a title V permit would create a disincentive for facilities to maintain their synthetic area source status by either voluntarily reducing their emissions or installing add-on controls in lieu of taking production limits, which would have a negative impact on air quality.

Response: The EPA disagrees that requiring title V permits would discourage facilities from maintaining their synthetic area source status, as facilities would in most, if not all, cases be subject to existing NESHAP applicable to chemical manufacturing major sources if they did not maintain synthetic area source status. For example, these sources would likely be subject to the HON or the MON, both of which require more frequent inspections and more stringent control of emissions. The EPA believes that avoiding these additional requirements would still provide incentive for facilities to maintain their synthetic area source status. In addition, all major sources of HAP subject to NESHAP are required to obtain a title V permit so the sources would still be required to comply with title V.

Comment: One commenter stated that it is punitive to require title V permits for sources that have already made a capital investment to achieve area source status and avoid title V permits in the past. The commenter stated that the EPA is ignoring the environmental benefit associated with the installation of federally-enforceable control devices by focusing on the uncontrolled potential of these sources.

Response: Pursuant to section 502(a) of the CAA, all area sources subject to CAA section 112 standards are required to obtain a title V permit unless the EPA makes a finding that title V is impracticable, infeasible or unnecessarily burdensome. Thus, there is no basis to support the statement that title V is punitive in nature and the EPA disagrees that requiring title V permits for synthetic area sources that installed

control devices is punitive. Furthermore, we are not ignoring the environmental benefit of controlling HAP emissions by requiring title V for certain CMAS sources.

In most, if not all, cases, synthetic area sources that installed controls would be subject to existing NESHAP applicable to major sources if they did not take synthetic area source limits and those standards are set at the maximum achievable control technology (MACT) level. Since MACT standards are technology based standards established based on the performance of the best performing source(s), it is likely the commenter would have had to achieve a comparable level of emissions reductions even if they had not taken the synthetic area source limit. While the EPA appreciates the environmental benefit attained by facilities that have installed these control devices to become area sources, we still believe that title V permitting is appropriate to, among other things, ensure: that synthetic area sources that installed controls are maintaining their emissions at the permitted level; that the public is able to review and evaluate the source's permit and compliance; that there is adequate monitoring, recordkeeping and reporting; and that the source's management is required to certify compliance with the CAA requirements applicable to the source.

Comment: Three commenters stated that if the EPA should choose to finalize the title V permit requirement, they supported the decision to limit this requirement to only facilities that have installed controls on an affected CMPU subject to the CMAS rule.

Response: The EPA has finalized revisions to the title V permit requirement; however, the EPA has made some revisions to the title V permit requirement to further clarify the applicability of title V to CMAS sources. The final rule only requires title V permits for facilities that have installed a federally-enforceable control device on at least one affected CMPU and the air pollution control device is required to maintain the source's emissions at area source levels.

Comment: One commenter expressed concern that while the language of the original final rule made it clear that their facility was exempted from the title V requirement, the proposed revisions made it ambiguous as to whether the facility would be required to obtain a title V permit. The commenter believed that the revised provisions for obtaining a title V permit would no longer exclude sources that were never a major source, and could instead be interpreted to mean that any synthetic area source, regardless of whether it was previously major or area, that installed a federally-enforceable control device on an affected CMPU would be subject to the title V permit requirement. The commenter requested that this requirement only apply to sources that became a synthetic area source as a direct result of installing the federally-enforceable control device.

Response: In response to comments on the proposed rule, the EPA has revised the final rule language to clarify the scope of the title V permit requirement. Specifically, the final rule requires a title V permit for any synthetic area source subject to the CMAS rule that would be a major source but for the installation of a federally-enforceable control device on at least one affected CMPU. The final title V requirement language affords no consideration to the purpose of the installed control device, other than it being necessary to maintain the source's emissions at area source levels, or the timing of the installation of the control device.

B. Requirements When Other Rules Overlap With the Final Rule

Comment: One commenter stated that it is not always clear what the most stringent provisions are when looking at overlapping provisions. The commenter requested that the EPA revise the rule to require facilities to make their best determination of stringency and submit to the appropriate agency for review and comment. The commenter also requested that states should be allowed to make streamlined determinations on stringency on an overall program stringency basis rather than individual rule provisions of overlapping rules.

Response: The EPA disagrees with the commenter that it is necessary to revise the final rule to allow for facilities to submit their stringency determinations for review and comment to their permitting authority. As the requirements of this section are entirely optional, we do not believe it to be appropriate to place additional burden on the local permitting authorities to make the determination of what the most stringent provisions are. Instead, we believe that this responsibility should continue to be placed on the facility. For those sources that are unable to determine the more stringent requirements, we continue to believe that it is more appropriate to evaluate requests for clarification on a case-by-case basis.

In addition, we also believe that it would be inappropriate for us to make a determination of equivalency among the numerous state streamlined programs with the requirements of the CMAS rule. As noted in the preamble to the proposed rule revisions, "[w]e did not include language that defines the more stringent requirements, as found in other rules, due to the great variety in characteristics of CMAS processes and the wide variety of compliance options in both the CMAS rule and overlapping rules. This variety makes it difficult to develop language that would not inadvertently allow a CMAS facility to comply with requirements less stringent than those contained in 40 CFR part 63, subpart VVVVVV, or less stringent than the required control level in an overlapping rule." (77 FR 4528). For these reasons, we are not revising these provisions in the final rule.

C. Requirement To Conduct Direct and Proximal Leak Inspections

Comment: Four commenters supported the proposed revisions to remove the requirement to conduct "direct and proximal" leak inspections and stated that the proposed sight, sound or smell inspections are appropriate.

Response: The EPA has finalized the proposed revisions to the leak detection requirements.

D. Requirement for Covers or Lids on Process Vessels

Comment: Three commenters requested that the EPA clarify that for metal HAP precipitate, or metal HAP in solution, the requirement to install a cover or lid on process vessels in metal HAP service does not apply. The commenters cited the low potential for emissions from these low vapor pressure metal HAP solutions as rationale for not imposing this requirement on such units. One commenter estimated that without this change, their facility would have to invest over $1,000,000 in covers/lids for their clarifiers, which are used to gravity-separate solids from solution and have very low potential for emissions. One commenter cited 40 CFR part 63, subpart CCCCCCC as an example of an area source rule that does not require this for metal HAP in solution. The commenter also provided examples of regulatory text that could be used in the CMAS rule.

Response: The EPA agrees with the commenters that the requirement to install a cover or lid for process vessels in metal HAP service is unnecessary for metal HAP in solution. As there is very little or no potential for air emissions to occur from these solutions, the rule need not require the process vessel to be covered. As such, we have revised the final rule to state that process vessels

that only contain metal HAP in a liquid solution or other form that will not result in particulate emissions of metal HAP (*e.g.,* metal HAP that is in ingot, paste, slurry or moist pellet form or other form) are not required to comply with the cover/lid requirement.

E. Requirement To Conduct Leak Inspections When Equipment Is in HAP Service

Comment: Three commenters suggested that leak inspections should be permitted to be conducted when equipment is in non-HAP (*i.e.,* VOC) service. Two commenters cited the limited personnel available to conduct leak inspections and the limited time windows for when equipment is in HAP service and inspections may be conducted as rationale.

One commenter noted that there is little difference between detecting leaks for streams in VOC vs. HAP service, as many HAP and non-HAP solvents have similar vapor and odor thresholds and both can be detected adequately by sight, sound or smell. The commenter also stated that since the MON allows for sources to assume that equipment is in HAP service, then the CMAS rule should permit it as well.

Response: The EPA agrees with the commenters that conducting leak inspections when equipment is in VOC service is acceptable for the reasons described above, and has revised the final rule to reflect this option, provided that leaks can be detected while in VOC service. As it may be very difficult for some facilities to conduct their inspections while equipment is in HAP service due to the limited amount of time and/or personnel available, this alternative will provide facilities with flexibility in conducting inspections while maintaining the same level of emissions reductions. This option does not apply to CMPU that contain metal HAP as particulate. For those units, the inspections must be conducted while the unit is in metal HAP service.

F. Applicability of the Family of Materials Concept

Comment: Two commenters supported the proposed revisions to the definition of ''family of materials.''

Response: The EPA has finalized the proposed revisions to this definition.

G. Requirements for Metal HAP Process Vents

Comment: Two commenters stated that the definition of metal HAP process vent should be revised to better reflect GACT for these emission points. The commenters state that in sulfuric acid regeneration units (SARUs), metal HAP are already controlled to >95 percent within the process itself and that it would be unreasonable to require an additional 95 percent control for metal HAP vents. The commenters recommend that a metal HAP process vent be defined as containing at least 50 ppmv metal HAP (similar to the batch and continuous process vents definitions), or that all vents from SARUs be excluded.

Response: The EPA agrees with the commenters that a metal HAP process vent should be defined as containing at least 50 ppmv metal HAP, consistent with the definitions of batch and continuous process vents. In reviewing other rules that regulate the chemical sector (*e.g.,* the MON) and define a process vent as containing at least 50 ppmv, the EPA found that it applied to process vents containing any HAP, not just organic HAP. As such, the EPA has revised the final rule to define a metal HAP process vent as containing at least 50 ppmv metal HAP.

Comment: One commenter requested that the EPA exempt process vents from CMPU using metal HAP in solution from the requirements for metal HAP process vents. The commenter cites the low potential for emissions from these low vapor pressure metal HAP solutions as rationale for exempting them. One commenter cited 40 CFR part 63, subpart CCCCCCC as an example of an area source rule that exempts metal HAP in solution. The commenter also provided examples of regulatory text that could be used in the CMAS rule.

Response: The EPA agrees with the commenter that it is not necessary to subject process vents from CMPU using metal HAP in solution to the requirements for metal HAP process vents. As the CMAS rule requires that CMPU process vents with total metal HAP emissions of less than 400 pounds/year (lb/yr) maintain records demonstrating that total metal HAP emissions are less than 400 lb/yr, and it is unlikely that process vents from CMPU handling only metal HAP in solution would ever exceed this value due to the little or no potential for air emissions to occur, this requirement results in an unnecessary recordkeeping burden for the facility. As such, we have revised the final rule to state that process vents from CMPU that only contain metal HAP in a liquid solution or other form that will not result in particulate emissions of metal HAP (*e.g.,* metal HAP that is in ingot, paste, slurry or moist pellet form or other form) are not required to comply with the metal HAP process vent requirements.

H. Compliance Date

Comment: Four commenters requested that the EPA extend the compliance date for a period of time ranging from 18 months to 3 years. The commenters all stated that the potential expansion of the applicability of the final rule would require additional time for sources to re-evaluate whether they would be subject to the rule. One commenter also cited the uncertainty surrounding the family of materials concept as finalized in the original rule and the fact that the EPA did not address the *de minimis* threshold issue that the Petitioners raised in their petition for reconsideration as reasons for extending the compliance date. The commenters stated that the EPA has the legal authority to extend the compliance date, citing the circumstances under which the EPA did so in the Boiler MACT reconsideration.

Response: The EPA agrees that a short extension of the compliance date is warranted for existing sources, not an extension of 18 months to 3 years. Given the amount of uncertainty regarding the applicability of the family of materials concept in the 2009 final rule, the EPA believes that with the revised definition of ''family of materials'' in these amendments, sources will need the short extension to evaluate applicability and determine the appropriate compliance approach. As such, the EPA believes it is reasonable to provide some additional period of time for facilities to review the revised final rule and determine which CMPU are subject to the requirements.

I. Technical Corrections

Comment: Six commenters objected to the proposed revision to base CMPU applicability on a collective 0.1 percent by weight (for carcinogens) or 1.0 percent by weight (for non-carcinogens) concentration, rather than an individual compound concentration. The commenters stated that this proposed change goes beyond being a ''technical correction'' as described in the proposal preamble, as it would significantly expand the scope of the rule and increase the compliance burden for facilities.

Two commenters stated that going to a collective HAP concentration would be inconsistent with the Toxics Release Inventory and the Occupational Safety and Health Administration Hazard Communication rules upon which the 0.1 percent and 1.0 percent thresholds were based and would be inconsistent with the definition of ''product'' in the CMAS rule.

Three commenters also noted that by having to use the collective concentration, facilities would no longer be able to use MSDS to determine applicability because MSDS are not provided for compounds at concentrations below 0.1 percent.

Response: The EPA agrees with the commenters that it is not appropriate to use a collective HAP concentration in determining applicability. It was not the EPA's intent to expand the applicability of the CMAS rule, but rather to clarify when it applied. As explained above and in section IV.F of this preamble, the commenters brought up numerous issues that the EPA had not considered when proposing this revision that would make determining applicability and complying with the rule extremely difficult. The expansion of the applicability was inadvertent and the final rule has not been revised as proposed.

Comment: Five commenters objected to the proposed revision to determine CMPU applicability based on a collective 50 ppmv concentration. The commenters state that, similar to the proposed revision to the 0.1/1.0 percent thresholds, this revision would significantly expand the scope of the rule, as 50 ppmv is a much lower concentration than the 0.1/1.0 percent concentration thresholds that had already been established. Additionally, the commenters stated that facilities would no longer be able to rely upon MSDS for determining applicability and the revision goes beyond being a "technical correction" as described in the proposal preamble.

Response: The EPA agrees with the commenters that it is not appropriate to establish a collective 50 ppmv concentration threshold for determining applicability. It was not the EPA's intent to expand the applicability of the CMAS rule, but rather to make the applicability consistent with the definitions of batch and continuous process vents. As explained above and in section IV.F of this preamble, the commenters brought up numerous issues that the EPA had not considered when proposing this revision, which would have inadvertently expanded the applicability of the rule. The expansion of the applicability was inadvertent and the EPA has not revised the final rule as proposed.

VI. What other actions are we taking?

In addition to requesting reconsideration of the above issues, the petition for reconsideration also requested the EPA take comment on three additional issues: (1) A *de minimis* exemption for all sources potentially subject to the rule; (2) a Petitioner proposed interpretation of the CAA section 112(c)(7) definition of "research or laboratory facilities" that would include commercial development activities; and (3) a pollution prevention alternative. The EPA is denying reconsideration of these issues because they failed to meet the standard for reconsideration under CAA section 307(d)(7)(B), and the EPA determined that reconsideration was not otherwise appropriate. Specifically, on these issues, the Petitioners have failed to show the following: That it was impracticable to raise their objections during the comment period; and/or that their concern is of central relevance to the outcome of the rules. We have concluded that no clarifications to the underlying rules are warranted for these issues.

Section 307(d)(7)(B) of the CAA states 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. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time 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, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b))."

As to the first procedural criterion for reconsideration, a petitioner must show why the issue could not have been presented during the comment period, either because it was impracticable to raise the issue during that time or because the grounds for the issue arose after the period for public comment (but within 60 days of publication of the final action). In the EPA's view, an objection is of central relevance to the outcome of the rule only if it provides substantial support for the argument that the promulgated regulation should be revised. See, *e.g.*, the EPA's *Denial of the Petition to Reconsider the Endangerment and Cause of Contribute Findings for the Greenhouse Gases under Section 202 of the Clean Air Act,* 75 FR 49561 (August 13, 2010). See also, 75 FR 49556, 49560–49563 (August 13, 2010), and 76 FR 4780, 4786–4788 (January 26, 2011) for additional discussion of the standard for reconsideration under CAA section 307(d)(7)(B).

A. De Minimis Exemption

Petitioners stated that the EPA should revise the CMAS final rule to include an across-the-board *de minimis* exemption for sources. The Petitioners argued that reconsideration would allow commenters to explain how, even with a *de minimis* exemption, the EPA could meet its statutory obligations.

This issue was contained in public comments submitted in response to the CMAS proposed rule published on October 6, 2008 (73 FR 58352). The EPA's responses to the comments are presented in section V.A of the preamble to the final rule (74 FR 56016–56018) and section 3.2 (pp. 3–3–3–4) of the October 2009 *Response to Comments Regarding National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources* document (See Docket Item No. EPA–HQ–OAR–2008–0334–0087).

The comments received on this issue demonstrate that the public had ample opportunity to comment on this issue and indeed did so. The EPA responded to those comments and sees no substantive reason to revisit this issue. Therefore, because the Petitioners did not demonstrate that it was impracticable to comment on this issue during the comment period on the proposed rule and the Petitioners did comment on it during the comment period for the 2008 proposal, the EPA is denying reconsideration of this issue.

B. Research and Development Interpretation

Petitioners stated that the EPA should take comment on an interpretation of "research and laboratory facility" in the CMAS final rule that would exempt equipment associated with "research" or "laboratory" activities as those terms are defined by the Petitioners. The Petitioners were concerned that, without an interpretation of the CAA section 112(c)(7) exemption for research and development facilities, the CMAS rule may pose a substantial compliance challenge for some sources.

This issue was contained in public comments submitted in response to the CMAS proposed rule published on October 6, 2008 (73 FR 58352). The EPA's responses to the comments are presented in section 3.5.3 (pp. 3–11) of the October 2009 *Response to Comments Regarding National Emission Standards for Hazardous Air Pollutants*

for Chemical Manufacturing Area Sources document (See Docket Item No. EPA–HQ–OAR–2008–0334–0087).

The comments received on this issue demonstrate that the public had ample opportunity to comment on this issue and indeed did so. The EPA responded to those comments and sees no substantive reason to revisit this issue. Therefore, because the Petitioners did not demonstrate that it was impracticable to comment on this issue during the comment period on the proposed rule and the Petitioners did comment on it during the comment period for the 2008 proposal, the EPA is denying reconsideration of this issue.

C. Pollution Prevention Alternative

Petitioners stated that the EPA should revise the CMAS final rule to include a pollution prevention alternative. The Petitioners argued that there would be broad interest in this alternative and that data would be made available for the EPA to specify requirements for such an alternative.

This issue was contained in public comments submitted in response to the CMAS proposed rule published on October 6, 2008 (73 FR 58352). The EPA's responses to the comments are presented in section 4.7 (pp. 4–7—4–8) of the October 2009 *Response to Comments Regarding National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources* document (See Docket Item No. EPA–HQ–OAR–2008–0334–0087).

The comments received on this issue demonstrate that the public had ample opportunity to comment on this issue, and indeed did so. The EPA responded to those comments and sees no substantive reason to revisit this issue. Therefore, because the Petitioners did not demonstrate that it was impracticable to comment on this issue during the comment period on the proposed rule and the Petitioners did comment on it during the comment period for the 2008 proposal, the EPA is denying reconsideration of this issue.

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 may raise 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.

B. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the OMB under the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR Number 2323.05. 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.

For this final rule, the EPA is adding affirmative defense to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to this ICR 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 $2,958 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 limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense.

Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of 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 VVVVVV 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.

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 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 Procedures Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations and small governmental jurisdictions.

For purposes of assessing the impacts of 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 (less than 500, 750 or 1,000 employees, depending on the specific NAICS Code under subcategory 325); (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.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This final rule will not impose any new requirements on any small entities because it does not impose any additional regulatory requirements beyond those already promulgated.

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. This final rule imposes no enforceable duty on any state, local or tribal governments or the private sector. Therefore, this final rule is not subject to the requirements of sections 202 and 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. This rule finalizes amendments to aid with compliance but does not change the level of the standards in the rule.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This final rule will not impose direct compliance costs on state or local governments and will not preempt state law. Thus, Executive Order 13132 does not apply to this action.

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

This 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. 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

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 final rule is not subject to Executive Order 13045 because it is based solely on technology performance. Further, this action does not relax the control measures on sources regulated by the final rule, and, therefore, will maintain the level of environmental protection.

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. Further, this action does not change the level of standards already in place.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995, Public Law No. 104–113, 12(d) (15 U.S.C. 272 note) directs 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. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the agency decides not use available and applicable VCS.

This final rulemaking 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, as amended, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because the rule amendments maintain 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 action does not relax the control measures on sources regulated by the final rule, and, therefore, will not cause emissions increases from these sources.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective December 21, 2012.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances.

Dated: December 14, 2012.

Lisa P. Jackson,

Administrator.

For the reasons cited 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 VVVVVV—[AMENDED]

■ 2. Lift the stay of subpart VVVVVV published October 25, 2012 (77 FR 65135).

■ 3. In § 63.11494, lift the stay on paragraph (e) published March 14, 2011 (76 FR 13514).

■ 4. Section 63.11494 is amended by:
■ a. Revising paragraph (a);
■ b. Adding paragraph (c)(1)(vii);
■ c. Revising the last sentence in paragraph (d) introductory text;
■ d. Revising paragraphs (e) and (f) to read as follows:

§ 63.11494 What are the applicability requirements and compliance dates?

(a) Except as specified in paragraph (c) of this section, you are subject to this subpart if you own or operate a chemical manufacturing process unit (CMPU) that meets the conditions specified in paragraphs (a)(1) and (2) of this section.

(1) The CMPU is located at an area source of hazardous air pollutant (HAP) emissions.

(2) HAP listed in Table 1 to this subpart (Table 1 HAP) are present in the CMPU, as specified in paragraph (a)(2)(i), (ii), (iii), or (iv) of this section.

(i) The CMPU uses as feedstock, any material that contains quinoline, manganese, and/or trivalent chromium at an individual concentration greater than 1.0 percent by weight, or any other Table 1 HAP at an individual concentration greater than 0.1 percent by weight. To determine the Table 1 HAP content of feedstocks, you may rely on formulation data provided by the manufacturer or supplier, such as the Material Safety Data Sheet (MSDS) for the material. If the concentration in an MSDS is presented as a range, use the upper bound of the range.

(ii) Quinoline is generated as byproduct and is present in the CMPU in any liquid stream (process or waste) at a concentration greater than 1.0 percent by weight.

(iii) Hydrazine and/or Table 1 organic HAP other than quinoline are generated as byproduct and are present in the CMPU in any liquid stream (process or waste), continuous process vent, or batch process vent at an individual concentration greater than 0.1 percent by weight.

(iv) Hydrazine or any Table 1 HAP is produced as a product of the CMPU.

* * * * *

(c) * * *

(1) * * *

(vii) Lead oxide production at Lead Acid Battery Manufacturing Facilities, subject to subpart PPPPPP of this part.

* * * * *

(d) * * * A CMPU using only Table 1 metal HAP is required to control only total CAA section 112(b) metal HAP in accordance with § 63.11495 and, if applicable, § 63.11496(f).

* * * * *

(e) Any area source that installed a federally-enforceable control device on an affected CMPU is required to obtain a permit under 40 CFR part 70 or 40 CFR part 71 if the control device on the affected CMPU is necessary to maintain the source's emissions at area source levels. For new and existing sources subject to this rule on December 21, 2012 and subject to title V as a result of this rule, a complete title V permit application must be submitted no later than December 21, 2013. New and existing sources that become subject to this rule after December 21, 2012 must submit a complete title V permit application no later than 12 months after becoming subject to this rule if the source is subject to title V as a result of this rule. Otherwise, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

(f) If you own or operate an existing affected source, you must achieve compliance with the applicable provisions in this subpart no later than March 21, 2013.

* * * * *

■ 5. Section 63.11495 is amended by:
■ a. Revising paragraphs (a)(1) and (a)(3);
■ b. Adding paragraph (c) heading; and
■ c. Adding paragraph (d) to read as follows:

§ 63.11495 What are the management practices and other requirements?

(a) * * *

(1) Each process vessel must be equipped with a cover or lid that must be closed at all times when it is in organic HAP service or metal HAP service, except for manual operations that require access, such as material addition and removal, inspection, sampling and cleaning. This requirement does not apply to process vessels containing only metal HAP that are in a liquid solution or other form that will not result in particulate emissions of metal HAP (e.g., metal HAP that is in ingot, paste, slurry, or moist pellet form or other form).

* * * * *

(3) You must conduct inspections of process vessels and equipment for each CMPU in organic HAP service or metal HAP service, as specified in paragraphs (a)(3)(i) through (v) of this section, to demonstrate compliance with paragraph (a)(1) of this section and to determine that the process vessels and equipment are sound and free of leaks. Alternatively, except when the subject CMPU contains metal HAP as particulate, inspections may be conducted while the subject process vessels and equipment are in VOC service, provided that leaks can be detected when in VOC service.

(i) Inspections must be conducted at least quarterly.

(ii) For these inspections, detection methods incorporating sight, sound, or smell are acceptable. Indications of a leak identified using such methods constitute a leak unless you demonstrate that the indications of a leak are due to a condition other than loss of HAP. If indications of a leak are determined not to be HAP in one quarterly monitoring period, you must still perform the inspection and demonstration in the next quarterly monitoring period.

(iii) As an alternative to conducting inspections, as specified in paragraph (a)(3)(ii) of this section, you may use Method 21 of 40 CFR part 60, appendix A–7, with a leak definition of 500 ppmv to detect leaks. You may also use Method 21 with a leak definition of 500 ppmv to determine if indications of a leak identified during an inspection conducted in accordance with paragraph (a)(3)(ii) of this section are due to a condition other than loss of HAP. The procedures in this paragraph (a)(3)(iii) may not be used as an alternative to the inspection required by paragraph (a)(3)(ii) of this section for process vessels that contain metal HAP as particulate.

(iv) Inspections must be conducted while the subject CMPU is operating.

(v) No inspection is required in a calendar quarter during which the subject CMPU does not operate for the entire calendar quarter and is not in organic HAP service or metal HAP service. If the CMPU operates at all during a calendar quarter, an inspection is required.

* * * * *

(c) *Startup, shutdown and malfunction.* * * *

(d) *General duty.* At all times, you must operate and maintain any affected CMPU, 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 CMPU.

■ 6. Section 63.11496 is amended by:
■ a. Revising the last sentence in paragraph (c);
■ b. Revising paragraphs (d) and (e) introductory texts;
■ c. Adding paragraph (e)(6);
■ d. Adding a sentence to the end of paragraph (f) introductory text;
■ e. Revising paragraphs (f)(3)(i)(C), (f)(3)(ii), and (g)(1);
■ f. Revising the first sentence in paragraph (g)(2); and
■ g. Revising paragraphs (g)(4)(i) and (g)(5).

The additions and revisions read as follows:

§ 63.11496 What are the standards and compliance requirements for process vents?

* * * * *

(c) * * * The TRE index value for continuous process vents and the annual emissions from batch process vents shall be determined for the individual streams before they are combined, and prior to any control (e.g., by subtracting any emission contributions from storage tanks, continuous process vents or batch process vents, as applicable), in order to determine the most stringent applicable requirements.

(d) *Halogenated streams.* You must determine if an emission stream is a halogenated vent stream by calculating the mass emission rate of halogen atoms in accordance with § 63.115(d)(2)(v). Alternatively, you may elect to designate the emission stream as halogenated. If you use a combustion device to comply with the emission limits for organic HAP from a halogenated batch process vent or a halogenated continuous process vent, you must use a halogen reduction device to meet the emission limit in either paragraph (d)(1) or (d)(2) of this section and in accordance with § 63.994 and the requirements referenced therein.

* * * * *

(e) *Alternative standard for organic HAP.* Exceptions to the requirements for the alternative standard requirements specified in Tables 2 and 3 to this subpart and § 63.2505 are specified in paragraphs (e)(1) through (6) of this section.

* * * * *

(6) CEMS requirements and data reduction requirements for CEMS specified in § 63.2450(j) apply.

* * * * *

(f) *Emissions from metal HAP process vents.* * * * The requirements of this paragraph (f) do not apply to metal HAP process vents from CMPU containing only metal HAP that are in a liquid solution or other form that will not result in particulate emissions of metal HAP (e.g., metal HAP that is in ingot, paste, slurry, or moist pellet form or other form).

* * * * *

(3) * * *

(i) * * *

(C) Operation and maintenance plan for the control device (including a preventative maintenance schedule consistent with the manufacturer's instructions for routine and long-term maintenance) and continuous monitoring system (CMS).

* * * * *

(ii) You must conduct a performance test or an engineering assessment for each CMPU subject to a HAP metals emissions limit in Table 4 to this subpart and report the results in your Notification of Compliance Status (NOCS). Each performance test or engineering assessment must be conducted under representative operating conditions, and sampling for each performance test must be conducted at both the inlet and outlet of the control device. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests. If you own or operate an existing affected source, you are not required to conduct a performance test if a prior performance test was conducted within the 5 years prior to the effective date using the same methods specified in paragraph (f)(3)(iii) of this section, and, either no process changes have been made since the test, or, if you can demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process changes.

* * * * *

(g) * * *

(1) *Requirements for performance tests.* (i) The requirements specified in § 63.2450(g)(1) through (4) apply instead of, or in addition to, the requirements specified in 40 CFR part 63, subpart SS.

(ii) Upon request, you shall make available to the Administrator, such records as may be necessary to determine the conditions of performance tests.

(2) *Design evaluation.* To determine initial compliance with a percent reduction or outlet concentration emission limit, you may elect to conduct a design evaluation as specified in § 63.1257(a)(1) instead of a performance test as specified in subpart SS of this part 63. * * *

* * * * *

(4) * * *

(i) You may measure pH or caustic strength of the scrubber effluent at least once per day for any halogen scrubber within a CMPU subject to this rule.

* * * * *

(5) *Startup, shutdown, malfunction (SSM).* Sections 63.996(c)(2)(ii) and 63.998(b)(2)(iii), (b)(6)(i)(A), (c)(1)(ii)(E) and (d)(3) do not apply for the purposes of this subpart.

* * * * *

■ 7. Section 63.11497 is amended by adding paragraph (d) to read as follows:

§ 63.11497 What are the standards and compliance requirements for storage tanks?

* * * * *

(d) *Combustion of halogenated streams.* If you use a combustion device to comply with the emission limits for organic HAP from a halogenated vent stream from a storage tank, you must reduce emissions in accordance with § 63.11496(d) and the requirements referenced therein.

■ 8. Section 63.11498 is amended by revising paragraph (a)(2) to read as follows:

§ 63.11498 What are the standards and compliance requirements for wastewater systems?

(a) * * *

(2) You are not required to determine the partially soluble concentration in wastewater that is hard piped to a combustion unit or hazardous waste treatment unit, as specified in Table 6, Item 2.b to this subpart.

* * * * *

■ 9. Section 63.11500 is amended by revising paragraph (a) to read as follows:

§ 63.11500 What compliance options do I have if part of my plant is subject to both this subpart and another Federal standard?

* * * * *

(a) *Compliance with other subparts of this part 63.* (1) If any part of a CMPU that is subject to the provisions of this

subpart is also subject to the provisions of another subpart of 40 CFR part 63, then compliance with any of the requirements in the other subpart of this part 63 that are at least as stringent as the corresponding requirements in this subpart VVVVVV constitutes compliance with this subpart VVVVVV.

(2) After the compliance dates specified in § 63.11494, at an offsite reloading or cleaning facility subject to § 63.1253(f), as referenced from § 63.2470(e) and Table 4 to subpart VVVVVV, compliance with the monitoring, recordkeeping, and reporting provisions of any other subpart of this part 63 constitutes compliance with the monitoring, recordkeeping, and reporting provisions of § 63.1253(f)(7)(ii) or (iii). You must identify in your notification of compliance status report required by § 63.11501(b) the subpart of this part 63 with which the owner or operator of the offsite reloading or cleaning facility complies.

* * * * *

■ 10. Section 63.11501 is amended by:
■ a. Revising the section heading;
■ b. Revising the last sentence in paragraph (c) introductory text;
■ c. Revising paragraph (c)(1) introductory text;
■ d. Adding paragraphs (c)(1)(vii) and (c)(1)(viii);
■ e. Revising paragraph (c)(4)(i);
■ f. Adding paragraph (c)(8);
■ g. Revising the last sentence in paragraph (d) introductory text; and
■ h. Adding paragraphs (d)(8) and (e) to read as follows:

§ 63.11501 What are the notification, recordkeeping, and reporting requirements, and how may I assert an affirmative defense for violation of emission standards during malfunction?

* * * * *

(c) *Recordkeeping.* * * * If you are subject, you must comply with the recordkeeping and reporting requirements of § 63.10(b)(2)(iii) and (vi) through (xiv), and the applicable requirements specified in paragraphs (c)(1) through (8) of this section.

(1) For each CMPU subject to this subpart, you must keep the records specified in paragraphs (c)(1)(i) through (viii) of this section.

* * * * *

(vii) Records of the date, time, and duration of each malfunction of operation of process equipment, control devices, recovery devices, or continuous monitoring systems used to comply with this subpart that causes a failure to meet a standard. The record must include a list of the affected sources or equipment, an estimate of the volume of each regulated pollutant emitted over the standard, and a description of the method used to estimate the emissions.

(viii) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.11495(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

* * * * *

(4) * * *

(i) Keep records of the vessel dimensions, capacity, and liquid stored, as specified in § 63.1065(a).

* * * * *

(8) For continuous process vents subject to Table 3 to this subpart, keep records of the occurrence and duration of each startup and shutdown of operation of process equipment, or of air pollution control and monitoring equipment.

(d) * * * Reports are required only for semiannual periods during which you experienced any of the events described in paragraphs (d)(1) through (8) of this section.

* * * * *

(8) *Malfunctions.* If a malfunction occurred during the reporting period, the report must include the number of instances of malfunctions that caused emissions in excess of a standard. For each malfunction that caused emissions in excess of a standard, the report must include a list of the affected sources or equipment, an estimate of the volume of each regulated pollutant emitted over the standard, and a description of the method used to estimate the emissions. The report must also include a description of actions you took during a malfunction of an affected source to minimize emissions in accordance with § 63.11495(d), including actions taken to correct a malfunction.

(e) *Affirmative defense for violation of emission standards during malfunction.* In response to an action to enforce the standards set forth in §§ 63.11495 through 63.11499, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the notification requirements in paragraph (e)(2) of this section, and must prove by a preponderance of evidence that:

(i) The violation:

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

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

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

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

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

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

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

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

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

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

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

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

(2) *Report.* If you seek to assert an affirmative defense, you must submit a written report to the Administrator, with all necessary supporting documentation, that you have met the requirements set forth in paragraph (e)(1) of this section. This affirmative defense report must be included in the first periodic compliance report,

deviation report, or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance report, deviation report, or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance report, deviation report, or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 11. Section 63.11502 is amended by:

■ a. In paragraph (a) adding in alphabetical order the terms "Batch operation (§ 63.2550)," "Continuous operation (§ 63.2550)," "Control device (§ 63.111)," and "Isolated intermediate (§ 63.2550)," and removing the term "Family of materials (§ 63.2550)"; and

■ b. In paragraph (b) adding in alphabetical order definitions for "Affirmative defense," "Engineering assessment," "Family of materials," "Hazardous waste treatment," "In VOC service," "Point of determination," and "Uncontrolled emissions," revising the second sentence of the definition of "Batch process vent," revising paragraph (1) of the definition of "Chemical manufacturing process," and revising the definitions for "In metal HAP service," "In organic HAP service," "Metal HAP process vent," and "Product" to read as follows:

§ 63.11502 What definitions apply to this subpart?

* * * * *

(b) * * *

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 process vent * * * Batch process vents include vents from batch operations and vents with intermittent flow from continuous operations that are not combined with any stream that originated as a continuous gas stream from the same continuous process. * * *

* * * * *

Chemical manufacturing process * * *

(1) All cleaning operations;

* * * * *

Engineering assessment means, but is not limited to, the following:

(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, TOC emission rate, organic HAP emission rate, metal HAP emission rate, or net heating value limit 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:

(i) Use of material balances based on process stoichiometry to estimate maximum organic HAP or metal HAP concentrations;

(ii) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities;

(iii) Estimation of TOC, organic HAP, or metal HAP concentrations based on saturation conditions; or

(iv) 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.

(5) All data, assumptions, and procedures used in the engineering assessment shall be documented.

* * * * *

Family of materials means a grouping of materials that have the same basic composition or the same basic end use or functionality; are produced using the same basic feedstocks, the same manufacturing equipment configuration and in the same sequence of steps; and whose production results in emissions of the same Table 1 HAP at approximately the same rate per pound of product produced. Examples of families of materials include multiple grades of same product or different variations of a product (e.g., blue, black and red resins).

* * * * *

Hazardous waste treatment, as used in the wastewater requirements, means treatment in any of the following units:

(1) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, subpart O, for which you have certified compliance with the interim status requirements of 40 CFR part 265, subpart O, or for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE at all times (including times when non-hazardous waste is being burned);

(2) A process heater or boiler for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H, for which you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H, or for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE at all times (including times when non-hazardous waste is being burned); or

(3) An underground injection well for which you have been issued a final permit under 40 CFR part 270 or 40 CFR part 144 and comply with the requirements of 40 CFR part 122.

In metal HAP service means that a process vessel or piece of equipment either contains or contacts a feedstock, byproduct, or product that contains metal HAP. A process vessel is no longer in metal HAP service after the vessel has been emptied to the extent practicable (*i.e.,* a vessel with liquid left on process vessel walls or as bottom clingage, but not in pools, due to floor irregularity, is considered completely empty) and any cleaning has been completed.

In organic HAP service means that a process vessel or piece of equipment either contains or contacts a feedstock, byproduct, or product that contains an organic HAP, excluding any organic HAP used in manual cleaning activities. A process vessel is no longer in organic HAP service after the vessel has been emptied to the extent practicable (*i.e.,* a vessel with liquid left on process vessel walls or as bottom clingage, but not in pools, due to floor irregularity, is considered completely empty) and any cleaning has been completed.

In VOC service means that a process vessel or piece of equipment either contains or contacts a fluid that contains VOC.

* * * * *

Metal HAP process vent means the point of discharge to the atmosphere (or inlet to a control device, if any) of a metal HAP-containing gas stream from any CMPU at an affected source containing at least 50 ppmv metal HAP. The metal HAP concentration may be determined using any of the following: process knowledge, an engineering assessment, or test data.

* * * * *

Point of determination means ''point of determination'' as defined in § 63.111 in subpart G of this part, except:

(1) The reference to Table 8 or Table 9 compounds means Table 9 (subpart G) or Table 7 (subpart VVVVVV) compounds;

(2) The reference to ''as determined in § 63.144 of this subpart'' does not apply for the purposes of this subpart; and

(3) The point of determination is made at the point where the stream exits the CMPU. If a recovery device is used, the point of determination is after the last recovery device.

Product means a compound or chemical which is manufactured as the intended product of the CMPU. Products include co-products. By-products, impurities, wastes, and trace contaminants are not considered products.

* * * * *

Uncontrolled emissions means organic HAP process vent emissions or metal HAP process vent emissions, as applicable, at the outlet of the last recovery device, if any, and prior to any control device. In the absence of both recovery devices and control devices, uncontrolled emissions are the emissions discharged to the atmosphere.

* * * * *

■ 12. Table 3 to subpart VVVVVV of part 63 is revised to read as follows:

TABLE 3 TO SUBPART VVVVVV OF PART 63—EMISSION LIMITS AND COMPLIANCE REQUIREMENTS FOR CONTINUOUS PROCESS VENTS

[As required in § 63.11496, you must comply with the requirements for continuous process vents as shown in the following table]

For . . .	You must . . .	Except . . .
1. Each continuous process vent with a TRE ≤1.0.	a. Reduce emissions of total organic HAP by ≥95 percent by weight (≥85 percent by weight for periods of startup or shutdown) or to ≤20 ppmv by routing emissions through a closed vent system to any combination of control devices (except a flare) in accordance with the requirements of § 63.982(c) and the requirements referenced therein; or	i. Compliance may be based on either total organic HAP or TOC; and ii. As specified in § 63.11496(g).
	b. Reduce emissions of total organic by HAP by routing all emissions through a closed-vent system to a flare (except that a flare may not be used to control halogenated vent streams) in accordance with the requirements of § 63.982(b) and the requirements referenced therein, or	i. Not applicable.
	c. Comply with the alternative standard specified in § 63.2505 and the requirements referenced therein	i. As specified in § 63.11496(e).
2. Halogenated vent stream that is controlled through combustion.	a. Comply with the requirements for halogen scrubbers in § 63.11496(d).	
3. Each continuous process vent with a TRE >1.0 but ≤4.0.	a. Comply with the requirements of § 63.982(e) and the requirements specified therein if a recovery device, as defined in § 63.11502, is used to maintain a TRE >1.0 but ≤4.0.	

■ 13. The entry for Item 1 of Table 5 to subpart VVVVVV of part 63 is revised to read as follows:

* * * * *

TABLE 5 TO SUBPART VVVVVV OF PART 63—EMISSION LIMITS AND COMPLIANCE REQUIREMENTS FOR STORAGE TANKS

For each . . .	You must . . .	Except . . .
1. Storage tank with a design capacity ≥40,000 gallons, storing liquid that contains organic HAP listed in Table 1 to this subpart, and for which the maximum true vapor pressure (MTVP) of total organic HAP at the storage temperature is ≥5.2 kPa and <76.6 kPa..	a. Comply with the requirements of subpart WW of this part;	i. All required seals must be installed by the compliance date in § 63.11494.

TABLE 5 TO SUBPART VVVVVV OF PART 63—EMISSION LIMITS AND COMPLIANCE REQUIREMENTS FOR STORAGE TANKS—Continued

For each . . .	You must . . .	Except . . .
	b. Reduce total organic HAP emissions by ≥95 percent by weight by operating and maintaining a closed-vent system and control device (other than a flare) in accordance with § 63.982(c); or	i. Compliance may be based on either total organic HAP or TOC; ii. When the term storage vessel is used in subpart SS of this part, the term storage tank, surge control vessel, or bottoms receiver, as defined in § 63.11502 of this subpart, applies; and iii. The requirements do not apply during periods of planned routine maintenance of the control device, as specified in § 63.11497(b).
	c. Reduce total HAP emissions by operating and maintaining a closed-vent system and a flare in accordance with § 63.982(b); or	i. The requirements do not apply during periods of planned routine maintenance of the flare, as specified in § 63.11497(b); and ii. When the term storage vessel is used in subpart SS of this part, it means storage tank, surge control vessel, or bottoms receiver, as defined in § 63.11502 of this subpart.
	d. Vapor balance in accordance with § 63.2470(e); or	i. To comply with § 63.1253(f)(6)(i), the owner or operator of an offsite cleaning or reloading facility must comply with § 63.11494 and § 63.11502 instead of complying with § 63.1253(f)(7)(ii), except as specified in item 1.d.ii and 1.2.iii of this table. ii. The reporting requirements in § 63.11501 do not apply to the owner or operator of the offsite cleaning or reloading facility. iii. As an alternative to complying with the monitoring, recordkeeping, and reporting provisions in §§ 63.11494 through 63.11502, the owner or operator of an offsite cleaning or reloading facility may comply as specified in § 63.11500 with any other subpart of this part 63 which has monitoring, recordkeeping, and reporting provisions as specified in § 63.11500.
	e. Route emissions to a fuel gas system or process in accordance with the requirements in § 63.982(d) and the requirements referenced therein.	i. When the term storage vessel is used in subpart SS of this part, it means storage tank, surge control vessel, or bottoms receiver, as defined in § 63.11502.
* *	* * *	* *

* * * * *

■ 14. Table 6 to subpart VVVVVV of part 63 is revised to read as follows:

TABLE 6 TO SUBPART VVVVVV OF PART 63—EMISSION LIMITS AND COMPLIANCE REQUIREMENTS FOR WASTEWATER SYSTEMS

[As required in § 63.11498, you must comply with the requirements for wastewater systems as shown in the following table]

For each . . .	You must . . .	And you must . . .
1. Wastewater stream	a. Discharge to onsite or offsite wastewater treatment or hazardous waste treatment	i. Maintain records identifying each wastewater stream and documenting the type of treatment that it receives. Multiple wastewater streams with similar characteristics and from the same type of activity in a CMPU may be grouped together for recordkeeping purposes.

TABLE 6 TO SUBPART VVVVVV OF PART 63—EMISSION LIMITS AND COMPLIANCE REQUIREMENTS FOR WASTEWATER SYSTEMS—Continued

[As required in § 63.11498, you must comply with the requirements for wastewater systems as shown in the following table]

For each . . .	You must . . .	And you must . . .
2. Wastewater stream containing partially soluble HAP at a concentration ≥10,000 ppmw and separate organic and water phases.	a. Use a decanter, steam stripper, thin film evaporator, or distillation unit to separate the water phase from the organic phase(s); or	i. For the water phase, comply with the requirements in Item 1 of this table, and ii. For the organic phase(s), recycle to a process, use as fuel, or dispose as hazardous waste either onsite or offsite, and iii. Keep records of the wastewater streams subject to this requirement and the disposition of the organic phase(s).
	b. Hard pipe the entire wastewater stream to onsite treatment as a hazardous waste, or hard pipe the entire wastewater stream to a point of transfer to onsite or offsite hazardous waste treatment.	i. Keep records of the wastewater streams subject to this requirement and the disposition of the wastewater streams.

■ 15. Table 8 to subpart VVVVVV of part 63 is revised to read as follows:

TABLE 8 TO SUBPART VVVVVV OF PART 63—EMISSION LIMITS AND COMPLIANCE REQUIREMENTS FOR HEAT EXCHANGE SYSTEMS

[As required in § 63.11499, you must comply with the requirements for heat exchange systems as shown in the following table]

For . . .	You must . . .	Except . . .
1. Each heat exchange system with a cooling water flow rate ≥8,000 gal/min and not meeting one or more of the conditions in § 63.104(a).	a. Comply with the monitoring requirements in § 63.104(c), the leak repair requirements in § 63.104(d) and (e), and the recordkeeping and reporting requirements in § 63.104(f); or	i. The reference to monthly monitoring for the first 6 months in § 63.104(b)(1) and (c)(1)(iii) does not apply. Monitoring shall be no less frequent than quarterly; ii. The reference in § 63.104(f)(1) to record retention requirements in § 63.103(c)(1) does not apply. Records must be retained as specified in §§ 63.10(b)(1) and 63.11501(c); and iii. The reference in § 63.104(f)(2) to "the next semi-annual periodic report required by § 63.152(c)" means the next semi-annual compliance report required by § 63.11501(f).
	b. Comply with the heat exchange system requirements in § 63.104(b) and the requirements referenced therein.	i. Not applicable.

■ 16. Table 9 to subpart VVVVVV of part 63 is amended by:

■ a. Revising the entry for 63.6(e)(1)(i) and (ii), (e)(3), and (f)(1);

■ b. Removing the entry for 63.7(a)(2), (b), (d), (e)(1)–(e)(3);

■ c. Adding new entries for 63.7(a)(2), (b), (d), (e)(2)–(e)(3) and 63.7(e)(1);

■ d. Removing the entry for 63.8(a)(1), (a)(4), (b), (c)(1)–(c)(3), (f)(1)–(5);

■ e. Adding new entries for 63.8(a)(1), (a)(4), (b), (c)(1)(ii), (c)(2)–(c)(3), (f)(1)–(5), 63.8(c)(1)(i), and 63.8(c)(1)(iii);

■ f. Revising the entry for 63.8(c)(4);

■ g. Removing the entry for 63.8(c)(6)–(c)(8), (d), (e), (f)(6);

■ h. Adding new entries for 63.8(c)(6)–(c)(8), (d)(1)–(d)(2), (e), (f)(6) and 63.8(d)(3);

■ i. Revising the entry for 63.8(g)(5);

■ j. Adding a new entry for 63.9(i);

■ k. Removing the entry for 63.10(b)(2)(i)–(b)(2)(v);

■ l. Adding new entries for 63.10(b)(2)(i), 63.10(b)(2)(ii), 63.10(b)(2)(iii), and 63.10(b)(2)(iv) and (v);

■ m. Removing the entry for 63.10(c)(7)–(c)(8), (c)(10)–(c)(12), (c)(15);

■ n. Adding new entries for 63.10(c)(7)–(8), 63.10(c)(10), 63.10(c)(11), 63.10(c)(12), and 63.10(c)(15); and

■ o. Revising the entry for 63.10(d)(5).

The additions and revisions read as follows:

TABLE 9 TO SUBPART VVVVVV OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART VVVVVV

Citation	Subject	Applies to subpart VVVVVV	Explanation
* * *	* * *	* * *	
63.6(e)(1)(i) and (ii), (e)(3), and (f)(1).	SSM Requirements	No	See § 63.11495(d) for general duty requirement.
* * *	* * *	* * *	
63.7(a)(2), (b), (d), (e)(2)–(e)(3)	Performance Testing Schedule, Notification of Performance Test, Performance Testing Facilities, and Conduct of Performance Tests.	Yes/No	Requirements apply if conducting test for metal HAP control; requirements in §§ 63.997(c)(1), (d), (e), and 63.999(a)(1) apply, as referenced in § 63.11496(g), if conducting test for organic HAP or hydrogen halide and halogen HAP control device.
63.7(e)(1)	Performance Testing	No	See § 63.11496(f)(3)(ii) if conducting a test for metal HAP emissions. See §§ 63.11496(g) and 63.997(e)(1) if conducting a test for continuous process vents or for hydrogen halide and halogen emissions. See §§ 63.11496(g) and 63.2460(c) if conducting a test for batch process vents.
63.8(a)(1), (a)(4), (b), (c)(1)(ii), (c)(2)–(c)(3), (f)(1)–(5).	Monitoring Requirements	Yes	
63.8(c)(1)(i)	General Duty to Minimize Emissions and CMS Operation.	No	
63.8(c)(1)(iii)	Requirement to Develop SSM Plan for CMS.	No	
* * *	* * *	* * *	
63.8(c)(4)		Yes	Only for CEMS. CPMS requirements in 40 CFR part 63, subpart SS are referenced from § 63.11496. Requirements for COMS do not apply because subpart VVVVVV does not require COMS.
* * *	* * *	* * *	
63.8(c)(6)–(c)(8), (d)(1)–(d)(2), (e), (f)(6).		Yes	Requirements apply only if you use a continuous emission monitoring system (CEMS) to demonstrate compliance with the alternative standard in § 63.11496(e).
63.8(d)(3)	Written Procedures for CMS	Yes	Requirement applies except for last sentence, which refers to an SSM plan. SSM plans are not required.
* * *	* * *	* * *	
63.8(g)(5)		No	Data reduction requirements for CEMS are specified in § 63.2450(j)(4), as referenced from § 63.11496. CPMS requirements are specified in 40 CFR part 63, subpart SS, as referenced from § 63.11496.
* * *	* * *	* * *	
63.9(i)		Yes	
* * *	* * *	* * *	
63.10(b)(2)(i)	Recordkeeping of Occurrence and Duration of Startups and Shutdowns.	No	See § 63.11501(c)(8) for recordkeeping of occurrence and duration of each startup and shutdown for continuous process vents that are subpart to Table 3 to this subpart.
63.10(b)(2)(ii)	Recordkeeping of Malfunctions	No	See § 63.11501(c)(1)(vii) and (viii) for recordkeeping of (1) date, time, duration, and volume of excess emissions and (2) actions taken during malfunction.
63.10(b)(2)(iii)	Maintenance Records	Yes	
63.10(b)(2)(iv) and (v)	Actions Taken to Minimize Emissions During SSM.	No	

TABLE 9 TO SUBPART VVVVVV OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART VVVVVV—Continued

* * * * * * *

Citation	Subject	Applies to subpart VVVVVV	Explanation
* *	* *	*	* * *
63.10(c)(7)–(8)	Additional Recordkeeping Requirements for CMS—Identifying Exceedances and Excess Emissions.	Yes	
63.10(c)(10)	Recordkeeping Nature and Cause of Malfunctions.	No	See § 63.11501(c)(1)(vii) and (viii) for malfunctions recordkeeping requirements.
63.10(c)(11)	Recording Corrective Actions	No	See § 63.11501(c)(1)(vii) and (viii) for malfunctions recordkeeping requirements.
63.10(c)(12)		Yes	
63.10(c)(15)	Use of SSM Plan	No	
* *	* *	*	* * *
63.10(d)(5)	SSM Reports	No	See § 63.11501(d)(8) for reporting requirements for malfunctions.

* * * * * * *

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Part IV

Environmental Protection Agency

40 CFR Parts 60 and 63

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2008–0708, FRL–9756–4]

RIN 2060–AQ58

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is finalizing amendments to the national emission standards for hazardous air pollutants for stationary reciprocating internal combustion engines. The final amendments include alternative testing options for certain large spark ignition (generally natural gas-fueled) stationary reciprocating internal combustion engines, management practices for a subset of existing spark ignition stationary reciprocating internal combustion engines in sparsely populated areas and alternative monitoring and compliance options for the same engines in populated areas. The EPA is establishing management practices for existing compression ignition engines on offshore vessels. The EPA is also finalizing limits on the hours that stationary emergency engines may be used for emergency demand response and establishing fuel and reporting requirements for certain emergency engines used for emergency demand response. The final amendments also correct minor technical or editing errors in the current regulations for stationary reciprocating internal combustion engines.

DATES: This final rule is effective on April 1, 2013. The incorporation by reference of certain publications listed in this final rule is approved by the Director of the Federal Register as of April 1, 2013.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2008–0708. The EPA also relies on materials in Docket ID Nos. EPA–HQ–OAR–2002–0059, EPA–HQ–OAR–2005–0029, and EPA–HQ–OAR–2005–0030 and incorporates those dockets into the record for this final rule. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the Air and Radiation Docket, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Melanie King, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541–2469; facsimile number (919) 541–5450; email address *king.melanie@epa.gov.*

SUPPLEMENTARY INFORMATION: *Background Information Document.* On June 7, 2012 (77 FR 33812), the EPA proposed amendments to the national emission standards for hazardous air pollutants (NESHAP) for stationary reciprocating internal combustion engines (RICE) and the new source performance standards (NSPS) for stationary engines. A summary of the public comments on the proposal and the EPA's responses to the comments, as well as the Regulatory Impact Analysis Report, are available in Docket ID No. EPA–HQ–OAR–2008–0708.

SUPPLEMENTARY INFORMATION: *Organization of This Document.* The following outline is provided to aid in locating information in the preamble.

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I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

The purpose of this action is to finalize amendments to the NESHAP for stationary RICE under section 112 of the Clean Air Act (CAA). This final rule was developed to address certain issues that were raised by various stakeholders through lawsuits, several petitions for reconsideration of the 2010 RICE NESHAP amendments and other communications. This final rule also provides clarifications and corrects minor technical or editing errors in the current RICE NESHAP and revises the NSPS for stationary engines, 40 CFR part 60, subparts IIII and JJJJ, for consistency with the RICE NESHAP.

This action is conducted under the authority of section 112 of the CAA, ''Hazardous Air Pollutants'' (HAP), which requires the EPA to establish NESHAP for the control of HAP from both new and existing sources in regulated source categories.

2. Summary of the Major Provisions of the Regulatory Action

After promulgation of the 2010 RICE NESHAP amendments, the EPA received several petitions for reconsideration, legal challenges, other communications raising issues related to practical implementation and certain factual information that had not been brought to the EPA's attention during the rulemaking. The EPA has considered this information and comments submitted in response to the proposed amendments, and believes that amendments to the rule to address certain issues are appropriate. Therefore, the EPA is finalizing amendments to 40 CFR part 63, subpart ZZZZ, NESHAP for stationary RICE. The current regulation applies to owners and operators of existing and new stationary RICE at major and area sources of HAP emissions. The applicability of the rule remains the same and is not changed by this final rule. The EPA is also finalizing amendments to the NSPS for stationary engines to conform with certain amendments finalized for the RICE NESHAP. The key amendments to the regulations are summarized in the following paragraphs.

The EPA is adding an alternative compliance demonstration option for stationary 4-stroke rich burn (4SRB) spark ignition (SI) engines subject to a 76 percent or more formaldehyde reduction requirement. Owners and operators of 4SRB engines will be permitted to demonstrate compliance with the 76 percent formaldehyde reduction emission standard by testing emissions of total hydrocarbons (THC) and showing that the engine is achieving at least a 30 percent reduction of THC emissions. The alternative compliance option provides a less expensive and less complex, but equally effective, method for demonstrating compliance than testing for formaldehyde.

Certain stationary RICE are maintained in order to be able to respond to emergency power needs. This action finalizes limitations on the operation of emergency engines for emergency demand response programs. The final rule limits operation of stationary emergency RICE as part of an emergency demand response program to within the 100 hours per year that were already permitted for maintenance and testing of the engines. The limitation of 100 hours per year ensures that a sufficient number of hours are available for engines to meet regional transmission organization and independent system operator tariffs and other requirements for participating in various emergency demand response programs and will assist in stabilizing the grid during periods of instability, preventing electrical blackouts and supporting local electric system reliability. The final rule also limits operation of certain emergency engines used to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region to 50 hours per year; this operation counts as part of the 100 hours of year permitted for maintenance and testing of the engine. This rule also establishes fuel and reporting requirements for emergency engines larger than 100 horsepower (HP) used for this purpose or used (or contractually obligated to be available) for more than 15 hours of emergency demand response per calendar year.

The EPA is finalizing management practices for owners and operators of existing stationary 4-stroke SI engines above 500 HP that are area sources of HAP emissions and where the engines are remote from human activity. A remote area is defined as either a Department of Transportation (DOT) Class 1 pipeline location,[1] or, if the engine is not on a pipeline, if within a 0.25 mile radius of the facility there are 5 or fewer buildings intended for human occupancy. The EPA determined that a 0.25 mile radius was appropriate because it is similar to the area used for the DOT Class 1 pipeline location. This final rule establishes management practices for these sources rather than numeric emission limits and associated testing and monitoring. This provision and the division of remote and non-remote engines into two separate subcategories addresses reasonable concerns with accessibility, infrastructure and staffing that stem from the remoteness of the engines and higher costs that would be associated with compliance with the existing requirements. Existing stationary 4-stroke SI engines above 500 HP at area sources that are in populated areas (defined as not in DOT pipeline Class 1 areas, or if not on a pipeline, if within a 0.25 mile radius of the engine there are more than 5 buildings intended for human occupancy) are subject to an equipment standard that requires the installation of HAP-reducing aftertreatment. The EPA has the discretion to set an equipment standard as generally available control technology (GACT) for engines located at area sources of HAP. Sources are required to test their engines to demonstrate compliance initially, perform catalyst activity check-ups and either monitor the catalyst inlet temperature continuously or employ high temperature shutdown devices to protect the catalyst.

To address how certain existing compression ignition (CI) engines are currently regulated, the EPA is specifying that any existing CI engine above 300 HP at an area source of HAP emissions that was certified to meet the Tier 3 engine standards[2] and was installed before June 12, 2006, is in compliance with the NESHAP. This provision creates regulatory consistency between the same engines installed before and after June 12, 2006. Engines at area sources of HAP for which construction commenced before June 12, 2006, are considered existing engines under the NESHAP.

The EPA is finalizing amendments to the requirements for existing stationary Tier 1 and Tier 2 certified CI engines located at area sources that are subject to state and locally enforceable requirements requiring replacement of the engine by June 1, 2018. This addresses a specific concern regarding the interaction of the NESHAP with certain rules for agricultural engines in the San Joaquin Valley in California. The EPA is allowing these engines to meet management practices under the RICE NESHAP from the May 3, 2013, compliance date until January 1, 2015, or 12 years after installation date, but not later than June 1, 2018. This provision addresses concerns about requiring owners and operators to install controls on their engines in order to meet the RICE NESHAP, and then having to replace their engines shortly thereafter due to state and local rules specifying the replacement of engines. Owners and operators will have additional time to replace their engines without having to install controls, but are required to use management practices during that period.

Another change the EPA is making is to broaden the definition of remote area sources in Alaska in the RICE NESHAP. Previously, remote areas were considered those that are not on the Federal Aid Highway System (FAHS). This change permits existing stationary CI engines at other remote area sources in Alaska to meet management practices rather than numerical emission standards likely to require

[1] A Class 1 location is defined as an offshore area or any class location unit that has 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.

[2] See 40 CFR part 89—Control of Emissions From New and In-Use Nonroad Compression-Ignition Engines.

aftertreatment. These remote areas have the same challenges as areas not on the FAHS, and complying with the current rule would similarly be prohibitively costly and potentially infeasible. In addition to area sources located in areas of Alaska that are not accessible by the FAHS being defined as remote and subject to management practices, any stationary RICE in Alaska meeting all of the following conditions are subject to management practices:

(1) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid, and

(2) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes, and

(3) The generating capacity of the area source is less than 12 megawatts (MW), or the stationary RICE is used exclusively for backup power for renewable energy.

The last significant change the EPA is finalizing is to require compliance with management practices rather than numeric emission limits in the RICE NESHAP for existing CI RICE on offshore drilling vessels on the Outer Continental Shelf (OCS) that become subject to the RICE NESHAP as a result of the operation of the OCS regulations (40 CFR part 55). The final amendments specify that owners and operators of existing non-emergency CI RICE with a site rating greater than 300 HP on offshore drilling vessels on the OCS are required to change the oil every 1,000 hours of operation or annually, whichever occurs first; inspect and clean air filters every 750 hours of operation or annually and replace as necessary; inspect fuel filters and belts, if installed, every 750 hours of operation or annually and replace as necessary; and inspect all flexible hoses every 1,000 hours of operation or annually and replace as necessary. Owners and operators can elect to use an oil analysis program to extend the oil change requirement.

3. Costs and Benefits

These final amendments will reduce the capital and annual costs of the original 2010 amendments by $287 million and $139 million, respectively. The EPA estimates that with these final amendments, the capital cost of compliance with the 2010 amendments to the RICE NESHAP in 2013 is $840 million and the annual cost is $490 million ($2010). These costs are identical to the costs estimated for the amendments to the RICE NESHAP proposed on June 7, 2012, since the changes from the proposal do not affect the costs of the rule in the year 2013. The capital and annual costs of the original 2010 final rule and the 2010 final rule with these final amendments incorporated into the rule are shown in Table 1.

TABLE 1—SUMMARY OF COST IMPACTS FOR EXISTING STATIONARY RICE

Engine	2010 Final rule		2010 Final rule with these final amendments
	Total Annual Cost		
SI	$253 million ($2009)	$251 million ($2010)	$115 million ($2010).
CI	$373 million ($2008)	$375 million ($2010)	$373 million ($2010).
	Total Capital Cost		
SI	$383 million ($2009)	$380 million ($2010)	$103 million ($2010).
CI	$744 million ($2008)	$748 million ($2010)	$740 million ($2010).

These final amendments would also result in decreases to the emissions reductions estimated in 2013 from the original 2010 RICE NESHAP amendments. The reductions that were estimated for the original 2010 RICE NESHAP amendments were 7,000 tpy of HAP, 124,000 tpy of CO, 2,800 tpy of PM, 96,000 tpy of NO_X and 58,000 tpy of VOC. The estimated reductions in 2013 from the 2010 RICE NESHAP rulemaking with these final amendments are 2,800 tons per year (tpy) of HAP, 36,000 tpy of carbon monoxide (CO), 2,800 tpy of particulate matter (PM), 9,600 tpy of nitrogen oxide (NO_X), and 36,000 tpy of volatile organic compounds (VOC). The difference in the emission reductions is primarily due to the changes to the requirements for existing 4-stroke stationary SI RICE at area sources of HAP that are in remote areas. These emission reduction estimates are identical to those estimated for the June 7, 2012, proposed amendments to the RICE NESHAP. The emission reductions of the original 2010 final rule and the 2010 final rule with these final amendments incorporated into the rule are shown in Table 2.

TABLE 2—SUMMARY OF REDUCTIONS FOR EXISTING STATIONARY RICE

Pollutant	Emission reductions (tpy) in the year 2013			
	2010 Final rule		2010 Final rule with these final amendments	
	CI	SI	CI	SI
HAP	1,014	6,008	1,005	1,778
CO	14,342	109,321	14,238	22,211
PM	2,844	N/A	2,818	N/A
NO_X	N/A	96,479	N/A	9,648
VOC	27,395	30,907	27,142	9,147

The EPA estimates the monetized co-benefits in 2013 of the original 2010 RICE NESHAP amendments with these final amendments incorporated to be $830 million to $2,100 million (2010 dollars) at a 3-percent discount rate and $740 million to $1,800 million (2010 dollars) at a 7-percent discount rate. The benefits that were estimated for the original 2010 RICE NESHAP amendments were $1,500 million to $3,600 million (2010 dollars) at a 3-percent discount rate and $1,300 million to $3,200 million (2010 dollars) at a 7-percent discount rate. A summary of the monetized co-benefits estimates for CI and SI engines at discount rates of 3 percent and 7 percent for the original 2010 final rule and the 2010 final rule with these final amendments incorporated into the rule is in Table 3 of this preamble.

TABLE 3—SUMMARY OF THE MONETIZED $PM_{2.5}$ CO-BENEFITS FINAL AMENDMENTS TO THE NESHAP FOR STATIONARY CI AND SI ENGINES

[millions of 2010 dollars] [a, b]

Pollutant	Emission reductions (tons per year)	Total monetized co-benefits (3 percent discount)	Total monetized co-benefits (7 percent discount)
Original 2010 Final Rules [c]			
Stationary CI Engines: Total Benefits	2,844 $PM_{2.5}$ 27,395 VOC	$950 to $2,300	$860 to $2,100.
Stationary SI Engines: Total Benefits	96,479 NO_X 30,907 VOC	$510 to $1,300	$470 to $1,100.
2010 Final Rules With These Final Amendments			
Stationary CI Engines: Directly emitted $PM_{2.5}$	2,818	$770 to $1,900	$690 to $1,700.
Stationary SI Engines: NO_X	9,648	$62 to $150	$55 to $140.

[a] All estimates are for the analysis year (2013) and are rounded to two significant figures so numbers may not sum across rows. The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as NO_X and directly emitted $PM_{2.5}$. It is important to note that the monetized co-benefits do not include reduced health effects from exposure to HAP, direct exposure to NO_2, exposure to ozone, ecosystem effects or visibility impairment.

[b] PM co-benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type.

[c] The benefits analysis for the 2010 final rules applied out-dated benefit-per-ton estimates compared to the updated estimates described in this preamble and reflected monetized co-benefits for VOC emissions, which limits direct comparability with the monetized co-benefits estimated for this final rule. In addition, these estimates have been updated from their original currency years to 2010$, so the rounded estimates for the 2010 final rules may not match the original RIAs.

We have not re-estimated the benefits for the final rule compared to the proposal because the emission reductions estimated for the final rule are the same as those estimated for the proposed amendments. Since the June 7, 2012, reconsideration proposal, the EPA has made several updates to the approach we use to estimate mortality and morbidity benefits in the PM NAAQS Regulatory Impact Analysis (RIA),[3, 4] including updated epidemiology studies, health endpoints, and population data. Although the EPA has not re-estimated the benefits for this rule to apply this new approach, these updates generally offset each other, and we anticipate that the rounded benefits estimated for this rule are unlikely to be different than those provided above.

More detail regarding the air quality and cost impacts and the benefits from this action can be found in section IV of this preamble.

B. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action include:

Category	NAICS [1]	Examples of regulated entities
Any industry using a stationary internal combustion engine as defined in the final amendments.	2211	Electric power generation, transmission, or distribution.
	622110	Medical and surgical hospitals.
	48621	Natural gas transmission.
	211111	Crude petroleum and natural gas production.
	211112	Natural gas liquids producers.
	92811	National security.

[1] North American Industry Classification System.

[3] U.S. Environmental Protection Agency (U.S. EPA). 2012a. *Regulatory Impact Analysis for the Proposed Revisions to the National Ambient Air Quality Standards for Particulate Matter.* EPA–452/R–12–003. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. June. Available at *http://www.epa.gov/ttnecas1/regdata/RIAs/PMRIACombinedFile_Bookmarked.pdf.*

[4] U.S. Environmental Protection Agency (U.S. EPA). 2012b. *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.* EPA–452/R–12–003. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. December. Available at *http://www.epa.gov/pm/2012/finalria.pdf.*

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether an engine is regulated by this action, owners and operators should examine the applicability criteria of this final rule. For any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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

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

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 1, 2013. Under section 307(d)(7)(B) of the CAA, only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Summary of Final Amendments

This action finalizes amendments to the NESHAP for RICE in 40 CFR part 63, subpart ZZZZ. This action also finalizes amendments to the NSPS for stationary engines in 40 CFR part 60, subparts IIII and JJJJ. The NESHAP for stationary RICE to regulate emissions of HAP was developed in several stages. The EPA initially addressed stationary RICE greater than 500 HP located at major sources of HAP emissions in 2004 (69 FR 33473). The EPA addressed new stationary RICE less than or equal to 500 HP located at major sources and new stationary RICE located at area sources in 2008 (73 FR 3568). Most recently, requirements for existing stationary RICE less than or equal to 500 HP located at major sources and existing stationary RICE located at area sources were finalized in 2010 (75 FR 9648 and 75 FR 51570).

The EPA is finalizing these amendments to address a number of issues that have been raised by different stakeholders through lawsuits, several petitions for reconsideration of the 2010 RICE NESHAP amendments, and other communications. The EPA is also finalizing revisions to 40 CFR part 60, subparts IIII and JJJJ for consistency with the RICE NESHAP and to make minor corrections and clarifications. The amendments that the EPA is finalizing in this action are discussed in this section. The changes from the proposal to this final rule are discussed in section III.

A. Total Hydrocarbon Compliance Demonstration Option

The EPA is adding an alternative method of demonstrating compliance with the NESHAP for existing and new stationary 4SRB non-emergency engines greater than 500 HP that are located at major sources of HAP emissions. Under these final amendments, the emission standard remains the same, that is, existing and new stationary 4SRB engines greater than 500 HP and located at major sources are still required to reduce formaldehyde emissions by 76 percent or more or limit the concentration of formaldehyde in the stationary RICE exhaust to 350 parts per billion by volume, dry basis or less at 15 percent oxygen (O_2). This final rule adds an alternative compliance demonstration option to the existing method of demonstrating compliance with the formaldehyde percent reduction standard. The current method is to test engines for formaldehyde. The alternative for owners and operators of 4SRB engines meeting a 76 percent or more formaldehyde reduction is to test their engines for THC showing that the engine is achieving at least a 30 percent reduction of THC emissions. Including this optional THC compliance demonstration option reduces the cost of compliance significantly while continuing to achieve the same level of HAP emission reduction because the emission standards would remain the same. As discussed in the June 7, 2012, proposal, data provided to EPA indicate that a strong relationship exists between percentage reductions of THC and percentage reductions of formaldehyde (the surrogate for HAP emissions in the NESHAP) on rich burn engines using non-selective catalytic reduction (NSCR). Data analyzed by the EPA indicate that if the NSCR is reducing THC by at least 30 percent from 4SRB engines, formaldehyde emissions are guaranteed to be reduced by at least 76 percent, which is the percentage reduction required for the relevant engines. Indeed, the percentage reduction of formaldehyde is invariably well above the 76 percent level, and is usually above 90 percent. Therefore, the EPA concluded that for SI 4SRB engines using NSCR and meeting the NESHAP by showing a percentage reduction of HAP, it would be appropriate to allow sources to demonstrate compliance with the NESHAP by showing a THC reduction of at least 30 percent. Owners and operators of existing stationary 4SRB engines less than or equal to 500 HP that are required to limit the concentration of formaldehyde in the stationary RICE exhaust to 10.3 parts per million by volume, dry basis (ppmvd) or less at 15 percent O_2 do not have the option to demonstrate compliance using THC and must continue to demonstrate compliance by testing for formaldehyde following the methods and procedures specified in the rule because the EPA could not verify a clear relationship between concentrations of THC and concentrations of formaldehyde in the exhaust from these SI 4SRB engines.

Owners and operators opting to use the THC compliance demonstration method must demonstrate compliance by showing that the average reduction of THC is equal to or greater than 30 percent. Owners and operators of 4SRB stationary RICE complying with the

requirement to reduce formaldehyde emissions and demonstrating compliance by using the THC compliance demonstration option must conduct performance testing using Method 25A of 40 CFR part 60, appendix A—Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer. Measurements of THC at the inlet and the outlet of the NSCR must be on a dry basis and corrected to 15 percent O_2 or equivalent carbon dioxide content. To correct to 15 percent O_2, dry basis, owners and operators must measure oxygen using Method 3, 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005) and measure moisture using Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03. Because owners and operators are complying with a percent reduction requirement, the method used must be suitable for the entire range of emissions since pre and post-catalyst emissions must be measured. Method 25A is capable of measuring emissions down to 5 ppmv and is, therefore, an appropriate method for measuring THC emissions for compliance demonstration purposes. The EPA is allowing sources the option to meet a minimum THC percent reduction of 30 percent by using Method 25A of 40 CFR part 60, appendix A to demonstrate compliance with the formaldehyde percent reduction in 40 CFR part 63, subpart ZZZZ.

B. Emergency Demand Response and Reliability

The EPA is finalizing certain revisions to the proposal regarding use of existing engines for emergency demand response and system reliability. Following is a summary of the prior requirements for these engines, including those in the 2010 regulation, a discussion of the information and input the EPA received in response to the proposal, and a description of the provisions being finalized in this action.

Existing emergency engines less than or equal to 500 HP located at major sources of HAP and existing emergency engines located at area sources of HAP were not regulated under the RICE NESHAP rulemakings finalized in 2004 and 2008. They could operate uncontrolled for an unlimited amount of time. The 2010 RICE NESHAP rulemaking for the first time established requirements for these existing emergency engines, requiring affected engines to comply by May 3, 2013, for stationary CI RICE and October 19, 2013, for stationary SI RICE. Under the RICE NESHAP requirements originally finalized in 2010, these existing emergency stationary engines must limit operation to situations like blackouts and floods and to a maximum of 100 hours per year for other specified operations beginning with the applicable compliance date in 2013 for the engine. The limitation of 100 hours per year included maintenance checks and readiness testing of the engine, as well as a limit of 15 hours per year for use as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. Under the 2010 regulation, existing emergency engines were required to meet management practice standards based on proper operation and maintenance of the engine; meeting these standards would not require installation of aftertreatment to control emissions.

Soon after the 2010 rule was final, the EPA received petitions for reconsideration of the 15-hour limitation for emergency demand response that was finalized in the 2010 rule. According to one petition, the 15-hour limit, while usually adequate to cover the limited hours in which these engines are expected to be called upon, would not be sufficient to allow these emergency engines to participate in emergency demand response programs since some regional transmission organizations and independent system operators require engines be available for more than 15 hours in order to meet emergency demand response situations. For example, PJM's Emergency Load Response Program requires that emergency engines guarantee that they will be available for 60 hours per year. By contrast, another petition asked EPA to eliminate the emergency demand response provision because of the adverse effects that the petitioner believes would result from increased emissions from these engines. The EPA received other comments that addressed the types of situations in which engines are called upon for emergency demand response and system reliability.

The EPA believes that the emergency demand response programs that exist across the country are important programs that protect the reliability and stability of the national electric service grid. The use of stationary emergency engines as part of emergency demand response programs can help prevent grid failure or blackouts, by allowing these engines to be used for limited hours in specific circumstances of grid instability prior to the occurrence of blackouts. A standard that requires owners and operators of stationary emergency engines that participate in emergency demand response programs to apply aftertreatment could make it economically infeasible for these engines to participate in these programs, impairing the ability of regional transmission organizations and independent system operators to use these relatively small, quick-starting and reliable sources of energy to protect the reliability of their systems in times of critical need. Information provided by commenters on the proposal indicates that these emergency demand response events are rarely called.[5]

The limited circumstances specified in the final rule for operation of stationary emergency engines for emergency demand response purposes include periods during which the Reliability Coordinator, or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert (EEA) Level 2 as defined in the North American Electric Reliability Corporation (NERC) Reliability Standard EOP–002–3, Capacity and Energy Emergency, and during periods where there is a deviation of voltage or frequency of 5 percent or more below standard voltage or frequency. During EEA Level 2 alerts there is insufficient energy supply and a true potential for electrical blackouts. System operators must call on all available resources during EEA Level 2 alerts in order to stabilize the grid to prevent failure. Therefore, this situation is a good indicator of severe instability on the system, which the EPA believes is appropriately considered an emergency situation. Consistent normal voltage provided by the utility is often called power quality and is an important factor in local electric system reliability. Reliability of the system requires electricity being provided at a normal expected voltage. The American National Standards Institute standard C84.1–1989 defines the maximum allowable voltage sag at below 5 percent. On the local distribution level local voltage levels are therefore important and a 5 percent or more change in the normal voltage or frequency is substantial and an indication that additional resources are needed to ensure local distribution system reliability.

In addition to the circumstances described above, the EPA also received comments on other situations where the

[5] See document number EPA–HQ–OAR–2008–0708–1142 in the rulemaking docket.

local transmission and distribution system operator has determined that there are conditions that could lead to a blackout for the local area where the ready availability of emergency engines is critical to system reliability. These include situations where:

- The engine is dispatched by the local balancing authority or local transmission and distribution system operator.
- The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.
- The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

The EPA believes the operation of emergency engines in these situations should be addressed in the final rule as well.

Therefore, based on the EPA's review of the petitions and comments that the EPA has received with respect to emergency demand response and system reliability, the EPA has concluded that it is appropriate to revise the provisions for stationary engines used in these limited circumstances. The provisions the EPA is amending are in §§ 63.6640(f) and 63.6675 of 40 CFR part 63, subpart ZZZZ. The final amendments to those sections specify that owners and operators of stationary emergency RICE can operate their engines as part of an emergency demand response program within the 100 hours already provided for operation for maintenance and testing. Owners and operators of stationary emergency engines can operate for up to 100 hours per year for emergency demand response and system reliability during periods in which the Reliability Coordinator, or other authorized entity as determined by the Reliability Coordinator, has declared an EEA Level 2 as defined in the NERC Reliability Standard EOP–002–3, Capacity and Energy Emergency, and during periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. In addition, existing emergency stationary RICE at area sources of HAP can operate for up to 50 hours per year if all of the following conditions are met:

- The engine is dispatched by the local balancing authority or local transmission and distribution system operator.
- The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.
- The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.
- The owner or operator has a pre-existing plan that contemplates the engine's operation under the circumstances described above; and
- The owner or operator identifies and records the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

For all engines operating to satisfy emergency demand response or system reliability under the circumstances described above, the hours spent for emergency demand response operation and local system reliability are added to the hours spent for maintenance and testing purposes and are counted towards the limit of 100 hours per year. If the total time spent for maintenance and testing, emergency demand response, and system reliability operation exceeds 100 hours per year, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

As noted above, the EPA received comments expressing concerns about the emissions from emergency engines, noting that the engines are likely to be dispatched on days when energy demand is high, which often coincides with days when air quality is poor. While the EPA is sensitive to these concerns, the availability of these engines for a more tailored response to emergencies may be preferable in terms of air quality impacts than relying on other generation, including coal-fired spinning reserve generation. After consideration of the concerns raised in the comments, the EPA is finalizing provisions that require stationary emergency CI RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response, or that operate for local system reliability, to use diesel fuel meeting the specifications of 40 CFR 80.510(b) beginning January 1, 2015, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted. The specifications of 40 CFR 80.510(b) require that diesel fuel have a maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent; this fuel is referred to as "ultra low sulfur diesel fuel" (ULSD). This emission reduction requirement was not part of the original 2010 rulemaking. Although the EPA does not have information specifying the percentage of existing stationary emergency CI engines currently using residual fuel oil or non-ULSD distillate fuel, the most recent U.S. Energy Information Administration data available for sales of distillate and residual fuel oil to end users [6] show that significant amounts of non-ULSD are still being purchased by end users that typically operate stationary combustion sources, including stationary emergency CI engines. For example, in the category of Commercial End Use, sales data for the year 2011 show that only 56 percent of the total distillate and residual fuel oil sold was ULSD. The data provided for Electric Power End Use show that 57 percent of total fuel sold was residual fuel oil. For Industrial End Use, the percentage of total fuel that was residual fuel oil was 26 percent. The EPA believes that requiring cleaner fuel for these stationary emergency CI engines will significantly limit or reduce the emissions of regulated air pollutants emitted from these engines, further protecting public health and the environment. Information provided to EPA by commenters [7] showed that the use of ULSD will significantly reduce emissions of air toxics, including metallic HAP (e.g., nickel, zinc, lead) and benzene.

In addition to the fuel requirement, owners and operators of stationary emergency CI RICE larger than 100 HP that operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response must report the dates and times the engines operate for emergency demand response annually to the EPA, beginning with operation during the 2015 calendar year. Owners and operators of these engines are also required to report the dates, times and situations that the engines operate to mitigate local transmission and/or

[6] U.S. Energy Information Administration. Distillate Fuel Oil and Kerosene Sales by End Use. Available at *http://www.eia.gov/dnav/pet/pet_cons_821use_dcu_nus_a.htm*.

[7] See document number EPA–HQ–OAR–2008–0708–1459 in the rulemaking docket.

distribution limitations annually to the EPA, beginning with operation during the 2015 calendar year. This information is necessary to determine whether these engines are operating in compliance with the regulations and will assist the EPA in assessing the impacts of the emissions from these engines.

The EPA is adding these requirements beginning in January, 2015, rather than upon initial implementation of the NESHAP for existing engines in May or October of 2013, to provide sources with appropriate lead time to institute these new requirements and make any physical adjustments to engines and other facilities like tanks or other containment structures, as well as any needed adjustments to contracts and other business activities, that may be necessitated by these new requirements.

The EPA is also amending the NSPS for stationary CI and SI engines in 40 CFR part 60, subparts IIII and JJJJ, respectively, to provide the same limitation for stationary emergency engines for emergency demand response and system reliability operation as for engines subject to the RICE NESHAP. The NSPS regulations currently do not include such a provision for emergency demand response or system reliability operation; the issue was not raised during the original promulgation of the NSPS. The EPA is adding an emergency demand response and system reliability provision under the NSPS regulations in these final amendments. The EPA is revising the existing language in §§ 60.4211(f) and 60.4219 of 40 CFR part 60, subpart IIII, and §§ 60.4243(d) and 60.4248 of 40 CFR part 60, subpart JJJJ, to specify that emergency engines must limit operation for engine maintenance and testing and emergency demand response to a maximum of 100 hours per year; 50 of the 100 hours may be used to operate to mitigate local reliability issues, as discussed previously for the RICE NESHAP.

The EPA is also finalizing amendments to the NSPS regulations that require owners and operators of stationary emergency engines larger than 100 HP that operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response to report the dates and times the engines operated for emergency demand response annually to the EPA, beginning with operation during the 2015 calendar year. Owners and operators of these engines are also required to report the dates, times and situations that the engines operate to mitigate local transmission and/or distribution limitations annually to the EPA, beginning with operation during the 2015 calendar year. The EPA anticipates that in most cases, the entity that dispatches the engines to operate, such as the curtailment service provider or utility, will report the information to the EPA on behalf of the facility that owns the engine. Thus, the burden of the reporting requirement will likely be on the entities that dispatch the engines. The EPA's burden estimate (see section V.B Paperwork Reduction Act) assumes the dispatching entity will report the date and hours dispatched without contacting individual engine operators. Emergency engines subject to 40 CFR part 60, subpart IIII are already required by subpart IIII to use diesel fuel that meets the requirements of 40 CFR 80.510(b).

The 2010 regulation specified that existing emergency engines at area sources of HAP that are residential, commercial, or institutional facilities were not subject to the RICE NESHAP requirements as long as the engines were limited to no more than 15 hours per year for emergency demand response. The EPA is specifying in the final rule that existing emergency engines at area sources of HAP that are residential, commercial, or institutional facilities are subject to the applicable requirements for stationary emergency engines in the RICE NESHAP if they operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response, or they operate to mitigate local transmission and/or distribution limitations. Information provided by commenters on the 2010 regulation and the amendments proposed in June 2012 indicates that these engines typically operate less than 15 hours per year for emergency demand response.

For stationary emergency engines above 500 HP at major sources of HAP that were installed before June 12, 2006, prior to these final amendments, there was no emergency demand response provision and there was no time limit on the use of emergency engines for routine testing and maintenance in § 63.6640(f)(2)(ii). Those engines were not the focus of the 2010 RICE NESHAP amendments; therefore, the EPA did not make any changes to the requirements for those engines as part of the 2010 amendments. For consistency, the EPA is now also revising 40 CFR part 63, subpart ZZZZ to require owners and operators of stationary emergency engines above 500 HP at major sources of HAP installed prior to June 12, 2006, to limit operation of their engines for maintenance and testing and emergency demand response program to a total of 100 hours per year. These engines would also be required to use diesel fuel meeting the specifications of 40 CFR 80.510(b) beginning January 1, 2015, however, if the engine operates or is contractually obligated to be available for more than 15 hours per year. Any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015 may be used until depleted. In addition to the fuel requirement, owners and operators of these engines must report the dates and times the engines operate for emergency demand response annually to the EPA, beginning with operation during the 2015 calendar year.

More detail regarding the public comments regarding emergency demand response and the EPA's responses can be found in the Response to Public Comments document available in the rulemaking docket.

C. Peak Shaving

In the June 7, 2012, proposal, the EPA proposed a temporary provision for existing stationary emergency engines located at area sources to apply the 50 hours per year that is allowed under § 63.6640(f) for non-emergency operation towards any non-emergency operation, including peak shaving. The peak shaving provision was proposed to expire in April 2017. As discussed further in section III.B, the EPA is not finalizing the proposed temporary 50-hour provision for existing stationary emergency engines located at area sources engaged in peak shaving and other non-emergency use as part of a financial arrangement with another entity. However, in consideration of the short time between this final rule and the May 3, 2013, or October 19, 2013, compliance dates for affected sources, this final rule includes a provision limiting the use of existing stationary emergency engines located at area sources to 50 hours per year prior to May 3, 2014, for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engines are operated as part of a peak shaving (load management) program with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system. This extension provides additional time so that these sources that wish to engage in peak shaving can come into compliance with the applicable requirements for non-emergency engines.

D. Non-Emergency Stationary SI RICE Greater Than 500 HP Located at Area Sources

The EPA is finalizing amendments to the requirements that apply to existing stationary non-emergency 4-stroke SI RICE greater than 500 HP located at area sources of HAP emissions, which are generally natural gas fired engines.

The EPA is creating a subcategory for existing spark ignition engines located in sparsely populated areas. Engines located in remote areas that are not close to significant human activity may be difficult to access, may not have electricity or communications, and may be unmanned most of the time. The costs of the emission controls, testing, and continuous monitoring requirements may be unreasonable when compared to the HAP emission reductions that would be achieved, considering that the engines are in sparsely populated areas. Moreover, the location of these engines is such that there would be limited public exposure to the emissions. The EPA believes that establishing a subcategory for SI engines at area sources of HAP located in sparsely populated areas accomplishes the agency's goals and is adequate in protecting public health. The EPA is creating this subcategory using criteria based on the existing DOT classification system for natural gas pipelines. This system classifies locations based on their distance to natural gas pipelines covered by the Pipeline and Hazardous Materials Safety Administration regulations. The DOT system defines a class location unit as an onshore area that extends 220 yards or 200 meters on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of natural gas pipeline. The DOT approach further classifies pipeline locations into Class 1 through Class 4 locations based on the number of buildings intended for human occupancy. A Class 1 location is defined as an offshore area or any class location unit that has 10 or fewer buildings intended for human occupancy. The DOT classification system also has special provisions for locations where buildings with four or more stories above ground are prevalent and locations that lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. To be considered remote under this final rule, a source on a pipeline could not fall under these special provisions and, in addition, must be in a Class 1 location. For those engines not associated with pipelines, the EPA is using similar criteria. An engine would be considered to be in sparsely populated areas if within 0.25 mile radius of the engine there are 5 or fewer buildings intended for human occupancy.

Owners and operators of existing stationary non-emergency 4-stroke lean burn (4SLB) and 4SRB RICE greater than 500 HP at area sources that are in sparsely populated areas as described above would be required to perform the following:

- Change oil and filter every 2,160 hours of operation or annually, whichever comes first;
- Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and
- Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.

Sources have the option to use an oil analysis program as described in § 63.6625(i) of the rule in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2d of the rule. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If none of these condemning limits are exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

Owners and operators of existing stationary 4SLB and 4SRB area source engines above 500 HP in sparsely populated areas would also have to operate and maintain the stationary RICE and aftertreatment control device (if any) according to the manufacturer's emission-related written instructions or develop their own maintenance plan, which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

Owners and operators of engines in sparsely populated areas would have to conduct a review of the surrounding area every 12 months to determine if the nearby population has changed. If the engine no longer meets the criteria for a sparsely populated area, the owner and operator must within 1 year comply with the emission standards specified below for populated areas.

For engines in populated areas, i.e., existing stationary 4SLB and 4SRB non-emergency engines greater than 500 HP at area sources that are located on DOT Class 2 through Class 4 pipeline segments or, for engines not associated with pipelines, that do not meet the 0.25 mile radius with 5 or less buildings criteria, the EPA is revising the requirements that were finalized in the 2010 rule. The EPA is adopting an equipment standard requiring the installation of a catalyst to reduce HAP emissions. Owners and operators of existing area source 4SLB non-emergency engines greater than 500 HP in populated areas would be required to install an oxidation catalyst. Owners and operators of existing area source 4SRB non-emergency engines greater than 500 HP in populated areas would be required to install NSCR. Owners and operators must conduct an initial test to demonstrate that the engine achieves at least a 93 percent reduction in CO emissions or a CO concentration level of 47 ppmvd at 15 percent O_2, if the engine is a 4SLB engine. Similarly, owners and operators must conduct an initial performance test to demonstrate that the engine achieves at least either a 75 percent CO reduction, a 30 percent THC reduction, or a CO concentration level of 270 ppmvd at 15 percent O_2 if the engine is a 4SRB engine. The initial test must consist of three test runs. Each test run must be of at least 15 minute duration, except that each test run conducted using appendix A to 40 CFR part 63, subpart ZZZZ must consist of one measurement cycle as defined by the method and include at least 2 minutes of test data phase measurement. To measure CO, emission sources must use the CO methods already specified in subpart ZZZZ, or appendix A to 40 CFR part 63, subpart ZZZZ. The THC testing

must be conducted using EPA Method 25A.

The owner or operator of both engine types must also use a high temperature shutdown device that detects if the catalyst inlet temperature is too high, or, alternatively, the owner or operator can monitor the catalyst inlet temperature continuously and maintain the temperature within the range specified in the rule. For 4SLB engines the catalyst inlet temperature must remain at or above 450 °F and at or below 1,350 °F. For 4SRB engines the temperature must be greater than or equal to 750 °F and less than or equal to 1,250 °F at the catalyst inlet.

Owners and operators must in addition to the initial performance test conduct annual checks of the catalyst to ensure proper catalyst activity. The annual check of the catalyst must at a minimum consist of one 15-minute run using the methods discussed above, except that each test run conducted using appendix A to 40 CFR part 63, subpart ZZZZ must consist of one measurement cycle as defined by the method and include at least 2 minutes of test data phase measurement. Owners and operators of 4SLB engines must demonstrate during the catalyst activity test that the catalyst achieves at least a 93 percent reduction in CO emissions or that the engine exhaust CO emissions are no more than 47 ppmvd at 15 percent O_2. Owners and operators of 4SRB engines must demonstrate during the catalyst activity check that their catalyst is reducing CO emissions by 75 percent or more, the CO concentration level at the engine exhaust is less than or equal to 270 ppmvd at 15 percent O_2, or THC emissions are being reduced by at least 30 percent.

If the emissions from the engine do not exceed the levels required for the initial test or annual checks of the catalyst, then the catalyst is considered to be working properly. If the emissions exceed the specified pollutant levels in the rule, the exceedance(s) is/are not considered a violation, but the owner or operator would be required to shut down the engine and take appropriate corrective action (e.g., repairs, clean or replace the catalyst, as appropriate). A follow-up test must be conducted within 7 days of the engine being started up again to demonstrate that the emission levels are being met. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the engine may not operate, except for purposes of start-up and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified.

E. Stationary CI RICE Certified to Tier Standards

The EPA is amending the requirements for any stationary CI engine certified to the Tier 3 standards in 40 CFR part 89 (Tier 2 for engines above 560 kilowatt (kW)) located at an area source and installed before June 12, 2006. The EPA is finalizing amendments to specify that any existing certified Tier 3 (Tier 2 for engines above 560 kW) CI engine that was installed before June 12, 2006, is in compliance with the RICE NESHAP. This amendment includes any existing stationary Tier 3 (Tier 2 for engines above 560 kW) certified CI engine located at an area source of HAP emissions. Without these amendments, Tier 3 engines, which were built to meet stringent emission standards, would not be able to comply with the applicable RICE NESHAP emission standards for existing engines without further testing and monitoring, and possible retrofit with further controls, due to differences in the emission standards and testing protocols in the RICE NESHAP versus the Tier 3 standards in 40 CFR part 89. However, an identical engine certified to the Tier 3 standards (or Tier 2 standards for engines above 560 kW) in 40 CFR part 89 that was installed after June 12, 2006, would not have to be retrofit in order to comply with the NESHAP. The EPA believes that the Tier 3 standards (Tier 2 for engines above 560 kW) are technologically stringent regulations and believes it is unnecessary to require further regulation of engines meeting these standards.

The EPA is also amending the requirements for existing stationary CI engines that are certified to the Tier 1 and Tier 2 standards in 40 CFR part 89, located at area sources of HAP, greater than 300 HP and subject to a state or local rule that requires the engine to be replaced. The EPA does not think it is appropriate to require emission controls on a stationary CI engine that is going to be retired only a short time after the rule goes into effect. These engines (equipped with aftertreatment) could end up being in operation for less than 2 years or at most only 5 years before having to be replaced with a certified Tier 4 engine. It would not be reasonable to require the engine owner to invest in costly controls and monitoring equipment for an engine that will be replaced shortly after the installation of the controls. Consequently, the EPA is allowing these engines to meet management practices from the applicable May 3, 2013, compliance date until January 1, 2015, or 12 years after installation date (whichever is later), but not later than June 1, 2018, after which time the CO emission standards in Table 2d of 40 CFR part 63, subpart ZZZZ) apply. The management practices include requirements for when to inspect and replace the engine oil and filter, air cleaner, hoses and belts. The complete details of which management practices are required are shown in Table 2d of the rule. Owners and operators of these existing stationary CI engines located at area sources of HAP emissions that intend to meet management practices rather than the emission limits prior to January 1, 2015, or 12 years after installation date, but not later than June 1, 2018, must submit a notification by March 3, 2013, stating that they intend to use this provision and identifying the state or local regulation that the engine is subject to.

F. Definition for Remote Areas of Alaska

The RICE NESHAP amendments finalized in 2010 specified less stringent requirements for existing non-emergency CI engines at area sources located in remote areas of Alaska. Remote areas are defined under the 2010 rule as those not accessible by the FAHS. In this action, the EPA is expanding the definition of remote areas of Alaska to extend beyond areas that are not accessible by the FAHS. The EPA is expanding the current definition because some areas that are accessible by the FAHS face the same challenges as areas that are not accessible, including high energy costs, extreme weather conditions, lengthy travel times, inaccessibility, and very low population density. Many of these areas are not connected to the electric grid and rely on back up diesel generation to support fluctuating renewable energy systems. The energy supply system is another area that is particularly different in Alaska compared to the rest of the country where the majority of customers are connected to the grid. These final amendments specify that existing stationary CI engines at area sources of HAP in areas of Alaska that are accessible by the FAHS and that meet all of the following criteria will also be considered remote and subject to management practices under the rule:

- The stationary CI engine is located in an area not connected to the Alaska Railbelt Grid,
- At least 10 percent of the power generated by the engine per year is used for residential purposes, and
- The generating capacity of the area source is less than 12 MW, or the engine

is used exclusively for backup power for renewable energy.

The EPA is limiting the remote classification to engines that are used at least partially for residential purposes, where the impact of higher energy costs is of greatest concern. The classification is further limited to sources that are used infrequently as backup for renewable power, or that are at smaller capacity facilities, which are generally in more sparsely populated areas.

G. Requirements for Offshore Vessels

The EPA is revising the requirements in the RICE NESHAP for existing non-emergency CI RICE greater than 300 HP on offshore vessels that are area sources of HAP. Engines on vessels on the OCS in certain circumstances become subject to the provisions of the RICE NESHAP as a result of the operation of the OCS regulations at 40 CFR part 55. The rationale for this revision is discussed further in section III.D. The EPA is finalizing the following management practice requirements for existing non-emergency CI RICE greater than 300 HP on offshore vessels that are area sources of HAP:

- Change oil every 1,000 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and the condemning limits are not exceeded;
- Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary;
- Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary; and
- Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

These sources may use an oil analysis program in order to extend the specified oil change requirement. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity and percent water content. The analysis must be conducted at the same frequency specified for changing the engine oil. If the condemning limits provided below are not exceeded, the engine owner or operator is not required to change the oil. If any of the condemning limits are exceeded, the engine owner or operator must change the oil within two business days or before continuing to use the engine, whichever is later. The condemning limits are as follows:

- Total Base Number is less than 30 percent of the Total Base Number of the oil when new; or
- Viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or
- Percent water content (by volume) is greater than 0.5.

Owners and operators of these existing stationary CI RICE must develop a maintenance plan that specifies how the management practices will be met and keep records to demonstrate that the required management practices are being met.

H. Miscellaneous Corrections and Revisions

The EPA is making some minor corrections and clarifications to the stationary engine rules to address miscellaneous issues. The revisions are as follows:

- Revising Tables 1b and 2b of 40 CFR part 63, subpart ZZZZ to correct language requiring the pressure drop to be at plus or minus 10 percent of 100 percent load for all engines. The engines that were regulated in 2010 are not subject to the load requirements and therefore the EPA is correcting these tables to make this clear.
- Adding a footnote to Table 1b of 40 CFR part 63, subpart ZZZZ stating that sources can petition the Administrator for a different temperature range consistent with Table 2b of the rule.
- Correcting rows 8 and 10 in Table 2d of 40 CFR part 63, subpart ZZZZ to indicate that the requirements apply to non-emergency, non-black start stationary RICE greater than 500 HP that are 4SLB and 4SRB that operate more than 24 hours per year, as intended in the original rule.
- Revising the language in § 63.6625(b) of 40 CFR part 63, subpart ZZZZ that states "* * * in paragraphs (b)(1) through (5) of this section" to "in paragraphs (b)(1) through (6) of this section."
- Changing Tables 2c and 2d of 40 CFR part 63, subpart ZZZZ, where it currently specifies to inspect air cleaner, to also specify that it must be replaced as necessary.
- Revising § 63.6620(b) of 40 CFR part 63, subpart ZZZZ to indicate that testing must be conducted within plus or minus 10 percent of 100 percent load for stationary RICE greater than 500 HP located at a major source (except existing non-emergency CI stationary RICE greater than 500 HP located at a major source) that are subject to testing.
- Specifying that, as was intended in the rule adding these requirements, the operating limitations (pressure drop and catalyst inlet temperature) in Tables 1b and 2b of 40 CFR part 63, subpart ZZZZ do not have to be met during startup.
- For consistency, and as provided in the original RICE NESHAP for other stationary RICE, clarifying in 40 CFR part 63, subpart ZZZZ that the existing stationary RICE regulated in 2010 (i.e., engines constructed before June 12, 2006, that are less than or equal to 500 HP located at major sources or engines located at area sources) must burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis in order to qualify as a landfill or digester gas engine under the rule.
- Clarifying § 60.4207(b) of 40 CFR part 60, subpart IIII to specify that owners and operators of stationary CI engines less than 30 liters per cylinder that are subject to the subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b), except owners and operators may use up any diesel fuel acquired prior to October 1, 2010, that does not meet the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.
- Adding appendix A to 40 CFR part 63, subpart ZZZZ, which includes procedures that can be used for measuring CO emissions from existing stationary 4SLB and 4SRB stationary RICE above 500 HP located at area sources of HAP that are complying with the emission limits in Table 2d of 40 CFR part 63, subpart ZZZZ.
- Reinstating the footnotes for Table 2 of 40 CFR part 60, subpart JJJJ. The footnotes were inadvertently removed when the rule was amended on June 28, 2011 (76 FR 37954).
- Adding "part 60" in Table 4 of the NESHAP, in row 2 where it refers to 40 CFR appendix A.
- Clarifying in § 63.6625(a) of 40 CFR part 63, subpart ZZZZ that a continuous emission monitoring system is only required to be installed at the outlet of the control device for engines that are complying with the requirement to limit the concentration of CO.
- Adding definitions of terms used in Equation 4 of § 63.6620 of 40 CFR part 63, subpart ZZZZ.
- Clarifying that, as was intended in the rule adding these requirements, all of the standards for stationary SI RICE in § 60.4231(b) of 40 CFR part 60, subpart JJJJ are for stationary SI RICE that use gasoline.
- Clarifying that, as was intended in the rule adding these requirements, all of the standards for stationary SI RICE in § 60.4231(c) of 40 CFR part 60, subpart JJJJ are for stationary SI RICE that are rich burn engines that use liquified petroleum gas (LPG).

• Clarifying that, as was intended in the rule adding these requirements, all of the standards for stationary SI RICE in § 60.4231(d) of 40 CFR part 60, subpart JJJJ are for stationary SI RICE that are not gasoline engines or rich burn engines that use LPG.

• Clarifying in § 63.6625(b)(1) and the entries for § 63.8(c)(1)(i) and (iii) in Table 8 of 40 CFR part 63, subpart ZZZZ that a startup, shutdown, and malfunction plan is not required for a continuous parameter monitoring system.

• Clarifying in the entry for § 63.10(b)(1) in Table 8 of 40 CFR part 63, subpart ZZZZ that the most recent two years of data do not have to be retained on site.

• Revising footnote 2 of Table 2c and footnote 1 of Table 2d of 40 CFR part 63, subpart ZZZZ to include a reference to § 63.6625(j), as was intended in the rule addressing these requirements.

III. Summary of Significant Changes Since Proposal

A. Emergency Demand Response and Reliability

The EPA proposed to limit operation of emergency stationary RICE as part of an emergency demand response program to within the 100 hours per year that is already permitted for maintenance and testing of the engines. The EPA proposed that owners and operators of stationary emergency engines could operate the engines for emergency demand response when the Reliability Coordinator, or other authorized entity as determined by the Reliability Coordinator, has declared an EEA Level 2 as defined in the NERC Reliability Standard EOP–002–3, Capacity and Energy Emergencies, plus during periods where there is a deviation of voltage or frequency of 5 percent or more below standard voltage or frequency. After considering public comments received on the proposed rule, the EPA is finalizing the proposed amendment to limit operation for maintenance and testing and emergency demand response to no more than 100 hours per year.

The EPA received some comments in support of the provision for emergency demand response operation, while other commenters opposed the limitation. The commenters who supported the provision noted that the engines are rarely called for emergency demand response, and that the EPA has limited the emergency demand response operation to emergency situations where a blackout is imminent. The commenters also noted that the public health impacts created by a widespread power outage outweigh the air quality impacts from the engines. The EPA agrees with the commenters that it is appropriate to include a provision for operation of emergency engines for a limited number of hours per year as part of emergency demand response programs to help prevent grid failure or blackouts. Preventing stationary emergency engines from being able to qualify and participate in emergency demand response programs without having to apply aftertreatment could force owners and operators to remove their engines from these programs, which could impair the ability of regional transmission organizations and independent system operators to use these relatively small, quick-starting and reliable sources of energy to protect the reliability of their systems.

The commenters who opposed the provision for demand response provided no significant argument that the conditions under which these engines would be permitted to operate for emergency demand response would not be emergency conditions. Commenters who opposed the provision were concerned about the air quality and health impacts of emissions from stationary engines. The commenters were concerned that recent actions by the Federal Energy Regulatory Commission (FERC) that impact demand response compensation in organized wholesale energy markets will greatly increase the amount of demand response participating in organized wholesale capacity markets. In response to the commenters, the EPA notes that, prior to the 2013 compliance dates for existing engines, there are no limitations on the hours of operation for those engines. The standards that go into effect in 2013 will for the first time establish requirements for these engines, including limitations on their hours of operation in certain situations such as emergency demand response, and ULSD fuel requirements which will reduce HAP emissions from the engines. Regarding the FERC regulations and their effect on use of demand response in capacity markets, these are comments more appropriately directed towards the FERC. As noted above, the emergency demand response situations during which the emergency engines may be used for a limited number of hours per year are appropriately considered emergency situations.

Commenters were also concerned that these engines would be called to operate for demand response on high ozone days, further contributing to nonattainment with ozone standards. However, other commenters noted that emergency demand response events do not predominantly occur on ozone exceedance days. These commenters also note that some of the commenters opposing use of emergency engines during emergency demand response would benefit by such a limitation because other emission sources may be used instead of the emergency engines, including sources that some of these commenters may operate, and that the effect on total emissions of using these alternative emission sources is not clear. Concerns about contribution to ozone nonattainment by stationary engines can be addressed through area-specific requirements such as state-based State Implementation Plans that would be directed towards ozone nonattainment areas. More detail regarding the public comments and the EPA's responses can be found in the Response to Public Comments document available in the rulemaking docket.

As mentioned in the previous paragraph, in response to the concerns about the air quality impact of emissions from emergency engines operating in emergency demand response programs, and based on public comments received on the proposed rule, the EPA is finalizing a requirement for owners and operators of existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that use diesel fuel and operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response to use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. This fuel requirement also applies to owners and operators of new emergency CI stationary RICE with a site rating of more than 500 brake HP with a displacement of less than 30 liters per cylinder located at a major source of HAP that use diesel fuel and operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response. Owners and operators must begin meeting this ULSD fuel requirement on January 1, 2015, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted. As noted by commenters on the proposed amendments and as discussed in section II.B, requiring the use of diesel fuel meeting the requirements of 40 CFR 80.510(b) is expected to reduce the HAP emissions significantly from the engines compared to emissions resulting from use of unregulated diesel fuel. The fuel

requirement begins on January 1, 2015, in order to give affected sources appropriate lead time to institute these new requirements and make any physical adjustments to engines and other facilities like tanks or containment structures, as well as any needed adjustments to contracts and other business activities, that may be necessitated by these new requirements.

The final amendments also require owners and operators of emergency stationary RICE larger than 100 HP that operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response to submit an annual report to the EPA documenting the dates and times that the emergency stationary RICE operated for emergency demand response, beginning with the 2015 calendar year. Commenters on the proposed amendments recommended that the EPA gather information on the impacts of the emissions from emergency engines during emergency demand response situations. The EPA agrees that a reporting requirement will increase the EPA's ability to ensure that these engines are operating in compliance with the regulations and that it will provide further information regarding the impacts of these engines on emissions. In response to these comments, the EPA is establishing a requirement to annually report to EPA the engine location and duration of operation for emergency demand response. This information will be used by the EPA, as well as state and local air pollution control agencies, to assess the health impacts of the emissions from these engines and to aid the EPA in ensuring that these engines comply with the regulations. Additional discussion of the rationale for the fuel and reporting requirements, as well as responses to other significant comments regarding emergency engines engaged in emergency demand response, can be found in the Response to Public Comments document in the docket.

Public commenters, in particular the National Rural Electric Cooperative Association (NRECA), indicated that the proposed EEA Level 2 and 5 percent voltage or frequency deviation triggers did not account for situations when the local balancing authority or transmission operator for the local electric system has determined that electric reliability is in jeopardy, and recommended that the EPA include additional situations where the local transmission and distribution system operator has determined that there are conditions that could lead to a blackout for the local area. The comments from NRECA indicated that rural distribution lines are not configured in a typical grid pattern, but instead have distribution lines that can run well over 50 miles from a substation and regularly extend 15 miles or longer. During periods of exceptionally heavy stress within the region or sub-region, electricity from regional power generators may not be available because of transmission constraints, according to the commenter. The commenter indicated that in many cases, there may be only one transmission line that feeds the rural distribution system, and no alternative means to transmit power into the local system.

In response to those comments and in recognition of the unique challenges faced by the local transmission and distribution system operators in rural areas, the EPA is specifying in the final rule that existing emergency stationary RICE at area sources can be used for 50 hours per year as part of a financial arrangement with another entity if all of the following conditions are met:

- The engine is dispatched by the local balancing authority or local transmission and distribution system operator.
- The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.
- The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.
- The power is provided only to the facility itself or to support the local transmission and distribution system.
- The owner or operator identifies and records the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

Engines operating in systems that do not meet the conditions described here will not be considered emergency engines if they operate for these purposes as part of a financial arrangement with another entity.

Stationary emergency CI RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder located at area sources that operate for this purpose are also required to use diesel fuel meeting the specifications of 40 CFR 80.510(b) beginning January 1, 2015, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted. Owners and operators of these engines are also required to report the dates and times the engines operated for this purpose annually to the EPA, beginning with operation during the 2015 calendar year. The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine. Further discussion of the rationale for the changes is available in the Response to Public Comments document in the docket.

B. Peak Shaving

The EPA proposed a temporary provision for existing stationary emergency engines located at area sources to apply the 50 hours per year that is allowed under § 63.6640(f) for non-emergency operation towards any non-emergency operation, including operation as part of a financial agreement with another entity. The peak shaving provision was proposed to expire in April 2017. The purpose of the proposed provision for peak shaving was to give sources an additional resource for maintaining reliability while facilities are coming into compliance with the NESHAP From Coal and Oil-Fired Electric Utility Steam Generating Units (77 FR 9304, February 16, 2012). Based on public comments received on the proposal, the EPA is not finalizing the proposed provision for peak shaving in this action. As noted by the commenters, operation for peak shaving does not fairly come under the definition of emergency use as it is designed to increase capacity in the system, rather than responding to an emergency situation such as a blackout or imminent brownout. The EPA believes that peak shaving activity and other activities designed to increase capacity should be treated as part of long term capacity planning, not as use akin to emergencies. The EPA agrees with commenters who state that allowance for emergency engines to be used for peak shaving could well lead to increased use of these engines, particularly in situations that are not emergency situations. The EPA also agrees that use of internal combustion engines for peak shaving is not based on emergency use, but instead is generally based on the economic benefit gained by operating the engine rather than another power source. The EPA agrees with the commenters that there is not sufficient information on the record to show that these engines are needed to maintain reliability while facilities are coming

into compliance with the NESHAP From Coal and Oil-Fired Electric Utility Steam Generating Units, and the commenters who supported the limited temporary provision did not provide information to show that rule would cause reliability issues that necessitate the operation of these engines. The EPA believes that given this information, it is appropriate to treat use of internal combustion engines as peak power units not as emergency use but as normal power generation, and thus believes it is appropriate to require emissions aftertreatment requirements (or similar controls as appropriate for non-emergency engines) for engines engaging in these activities for compensation. Further discussion is available in the Response to Public Comments document in the docket.

However, in consideration of the short time between this final rule and the May 3, 2013, or October 19, 2013 compliance dates for affected sources, this final rule permits the use of existing stationary emergency engines located at area sources for 50 hours per year through May 3, 2014 for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engines are operated as part of a peak shaving (load management) program with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system. Owners and operators of these engines, which have heretofore not been regulated, may have taken actions based on the June 7, 2012, proposal that would now leave them in danger of being in noncompliance with the applicable requirements for the engine in the RICE NESHAP.

C. Non-Emergency Stationary SI RICE Greater Than 500 HP Located at Area Sources

The EPA proposed to require existing stationary non-emergency 4-stroke SI RICE greater than 500 HP located at area sources of HAP that are in sparsely populated areas to meet management practices. The proposed management practices required the engine owner and operator to change the oil and filter and inspect spark plugs, hoses and belts every 1,440 hours of operation or annually, whichever comes first. The proposed management practices were based on similar requirements for existing non-emergency stationary SI RICE smaller than 500 HP. The EPA received public comments indicating that the interval for performing the management practices for engines larger than 500 HP should be every 2,160 hours of operation or annually, whichever comes first. Commenters indicated that larger engines have increased capabilities compared to smaller size engines, which allows engines to extend the maintenance interval. Larger engines have increased oil capacities, use improved oil grades/synthetics, and use oil sweetening systems, according to the commenters. Commenters also noted that larger engines use better quality, more expensive spark plugs that last longer than 1,440 hours, and that less frequent maintenance intervals reduce the environmental impacts associated with disposing waste oils and traveling to remote locations. The EPA agrees with the arguments presented by the commenters. Therefore, in this final rule, EPA is requiring engine owners and operators to change the oil and filter and inspect spark plugs, hoses and belts every 2,160 hours of operation or annually, whichever comes first.

For existing stationary non-emergency SI 4SRB RICE that are in populated areas, the EPA proposed an equipment standard that required the installation of NSCR to reduce HAP emissions. The proposed rule required these engines to demonstrate that the catalyst achieves at least a 75 percent CO reduction or a 30 percent THC reduction. The EPA is retaining this requirement in this final rule, but is adding another option in response to public comments that allows the owner and operator of the engine to demonstrate that the catalyst achieves a CO concentration level of 270 ppmvd at 15 percent O_2. As noted by the public comments, this represents a 75 percent reduction from typical uncontrolled emissions from existing stationary non-emergency SI 4SRB RICE and is the CO standard required for new SI 4SRB engines in the NSPS for stationary SI engines. The EPA is also clarifying that, as was intended in the original proposal, engines located in Class 4 locations are not considered remote. More detail regarding the public comments and the rationale for these changes can be found in the Response to Public Comments document, which is available in the docket for this rulemaking.

D. Definition for Remote Areas of Alaska

The EPA proposed to expand the definition of remote areas of Alaska to extend beyond areas that are not accessible by the FAHS. Specifically, the EPA proposed that areas of Alaska that are accessible by the FAHS and that met all of the following criteria would also be considered remote and subject to management practices under the rule: (1) The stationary CI engine is located in an area not connected to the Alaska Railbelt Grid; (2) at least 10 percent of the power generated by the engine per year is used for residential purposes; and (3) the generating capacity of the area source is less than 12 MW, or the engine is used exclusively for backup power for renewable energy and is used less than 500 hours per year on a 10-year rolling average. After considering the public comments received on the proposed criteria, the EPA is finalizing the first two criteria as proposed, but finalizing a slightly different third criterion. In this final rule, existing CI engines at area sources of HAP are considered remote if they meet the first and second criteria above and they are either at a source with a generating capacity less than 12 MW, or used exclusively for backup power for renewable energy. Based on public comments received on the proposal, the EPA is not finalizing the limitation that the engine be used less than 500 hours per year on a 10-year rolling average. Commenters indicated that basing the applicability on the previous 10 years of operation would ignore recent investments in renewable energy that have significantly decreased engine hours of operation in recent years. The EPA is also defining ''backup power for renewable energy'' in this final rule as engines that provide backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5). The rationale for these changes can be found in the Response to Public Comments document available in the docket.

E. Requirements for Offshore Vessels

The RICE NESHAP does not on its face apply to mobile sources, including marine vessels. However, the regulations applicable to sources on the OCS, codified at 40 CFR part 55, specify that vessels are OCS sources when they are (1) permanently or temporarily attached to the seabed and erected thereon and used for the purpose of exploring, developing or producing resources there from, within the meaning of section 4(a)(1) of the OCS Lands Act (43 U.S.C. 1331, *et seq.*); or (2) physically attached to an OCS facility, in which case only the stationary sources aspects of the vessels will be regulated. 40 CFR 55.2. The OCS regulations provide that NESHAP requirements apply to a vessel that is an OCS source where the provisions are ''rationally related to the attainment and maintenance of the federal or state ambient air quality standards or the

requirements of part C of title I of the Act.'' 40 CFR 55.13(e).

The EPA received comments during the public comment period for the June 7, 2012, proposal recommending that the RICE NESHAP be amended such that for any existing non-emergency CI RICE above 300 HP on offshore vessels on the OCS that become subject to the RICE NESHAP as a result of the operation of the OCS regulations (40 CFR part 55), such engines may meet the NESHAP through management practices rather than numeric emission limits. This amendment was not contained or contemplated in the June 7, 2012, proposal. However, the comments indicated several significant issues related to application of the NESHAP to regulation of existing marine vessel engines located in the OCS as a result of the OCS regulations; in particular, whether the numerical standards applicable to other CI engines located at area sources (marine vessels located in the OCS are generally located at area sources) are technologically feasible for existing marine engines located in the OCS. Some commenters noted specific technological issues relevant to engines on marine vessels in the OCS. The commenters indicated that emission controls for existing CI RICE to meet the NESHAP may be technically infeasible due to weight and space constraints, catalyst fouling from the low-load engine operation required by the U.S. Coast Guard, safety concerns regarding engine backpressure and lack of catalyst vendor experience with retrofitting. Commenters suggested that, to the extent marine vessel engines become subject to the NESHAP as a result of the OCS regulations, these engines should be subject to GACT requirements that the commenters believe are more appropriate for these types of engines. The commenters indicated that management practices similar to those currently required in the rule for existing non-emergency stationary CI RICE smaller than 300 HP are more appropriate as GACT for existing non-emergency stationary CI RICE above 300 HP on vessels operating on the OCS.

Based on these comments, the EPA published a reopening of the comment period to take further comment on whether the RICE NESHAP should be revised to require management practices for these vessels (77 FR 60341, October 3, 2012). Based on the comments received during the two comment periods, the EPA agrees with the commenters that management practices are more reasonable as GACT for existing non-emergency stationary CI RICE larger than 300 HP on vessels operating on the OCS and is finalizing management practices for these engines. The EPA did not receive any public comments indicating that HAP emission controls were generally available and had been demonstrated for the large engines on the vessels. The final management practices include changing the oil every 1,000 hours of operation or annually, whichever comes first; inspecting and cleaning air filters every 750 hours of operation or annually, whichever comes first, and replacing as necessary; inspecting fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replacing as necessary; and inspecting all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replacing as necessary. Facilities have the option of using an oil analysis program to extend the oil change requirement. Additional discussion of the rationale for these changes can be found in the Response to Public Comments document available in the docket.

IV. Summary of Environmental, Energy and Economic Impacts

A. What are the air quality impacts?

The EPA estimates that the rule with the final amendments incorporated will reduce emissions from existing stationary RICE as shown in Table 4 of this preamble. The emissions reductions the EPA previously estimated for the 2010 amendments to the RICE NESHAP are shown for comparison. Reductions are shown for the year 2013, which is the first year the final RICE NESHAP will be implemented for existing stationary RICE.

TABLE 4—SUMMARY OF REDUCTIONS FOR EXISTING STATIONARY RICE

Pollutant	Emission Reductions (tpy) in the year 2013			
	2010 Final rule		2010 Final rule with these final amendments	
	CI	SI	CI	SI
HAP	1,014	6,008	1,005	1,778
CO	14,342	109,321	14,238	22,211
PM	2,844	N/A	2,818	N/A
NO_X	N/A	96,479	N/A	9,648
VOC	27,395	30,907	27,142	9,147

The EPA estimates that more than 900,000 stationary CI engines will be subject to the rule in total, but only a small number of stationary CI engines are affected by the final amendments in this action. The EPA did not estimate any changes in the reductions from the 2010 rule for the amendments associated with emergency engines. To determine emissions from emergency engines for the 2010 rule, the EPA estimated that these types of engines would on average operate for 50 hours per year. The average hours of operation for emergency engines is not expected to change based on the final amendments and 50 hours per year is still believed to be representative of average emergency engine operation. Information provided by commenters demonstrated that these engines have been operated very infrequently for emergency demand response events.[8] Therefore, the emissions previously calculated remain appropriate.

It is estimated that approximately 330,000 stationary SI engines will be subject to the rule in total; however, only a subset of stationary SI engines are affected by the final amendments in this action. The decrease in estimated reductions for SI engines is primarily due to final amendments to the requirements for existing 4SRB and 4SLB SI engines larger than 500 HP at area sources of HAP that are in remote areas. Those engines were required by the 2010 rule to meet emission limits that were expected to require the installation of aftertreatment to reduce emissions; under these final amendments, those engines are required

[8] See document number EPA–HQ–OAR–2008–0708–1142 in the rulemaking docket.

to meet management practices that would not require the installation of aftertreatment. Further information regarding the estimated reductions of this final rule can be found in the memorandum titled, "RICE NESHAP Reconsideration Final Amendments—Cost and Environmental Impacts," which is available in the docket (EPA–HQ–OAR–2008–0708). The EPA did not estimate any impacts associated with the minor changes to the NSPS for stationary CI and SI engines.

B. What are the cost impacts?

The final amendments are expected to reduce the overall cost of the original 2010 RICE NESHAP amendments. The EPA estimates that with these final amendments incorporated, the cost of the rule for existing stationary RICE will be as shown in Table 5 of this preamble. The costs the EPA previously estimated for the 2010 amendments to the RICE NESHAP are shown for comparison. The costs that were previously estimated are shown in the original year ($2008 for CI and $2009 for SI), as well as updated to 2010 dollars.

TABLE 5—SUMMARY OF COST IMPACTS FOR EXISTING STATIONARY RICE

Engine	2010 Final Rule		2010 Final Rule with these Final Amendments
Total Annual Cost			
SI	$253 million ($2009)	$251 million ($2010)	$115 million ($2010).
CI	$373 million ($2008)	$375 million ($2010)	$373 million ($2010).
Total Capital Cost			
SI	$383 million ($2009)	$380 million ($2010)	$103 million ($2010).
CI	$744 million ($2008)	$748 million ($2010)	$740 million ($2010).

Further information regarding the estimated cost impacts of the final amendments, including the cost of the final amendments in 2010 dollars, can be found in the memorandum titled, "RICE NESHAP Reconsideration Final Amendments—Cost and Environmental Impacts," which is available in the docket (EPA–HQ–OAR–2008–0708). The EPA did not estimate costs associated with the changes to the NSPS for stationary CI and SI engines. The changes to the NSPS are minor and are not expected to impact the costs of those rules.

C. What are the benefits?

Emission controls installed to meet the requirements of this final rule will generate benefits by reducing emissions of HAP as well as criteria pollutants and their precursors, including CO, NO_X and VOC. NO_X and VOC are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns) and ozone. The criteria pollutant benefits are considered co-benefits for this rule. For this final rule, the EPA was only able to quantify the health co-benefits associated with reduced exposure to $PM_{2.5}$ from emission reductions of NO_X and directly emitted $PM_{2.5}$. The EPA has not re-estimated the benefits from the proposal for this final rule because the emission reductions have not changed since the reconsideration proposal.[9]

The EPA previously estimated that the monetized co-benefits in 2013 of the stationary CI NESHAP would be $940 million to $2,300 million (2008 dollars) at a 3-percent discount rate and $850 million to $2,100 million (2008 dollars) at a 7-percent discount rate.[10] For stationary SI engines, EPA previously estimated that the monetized co-benefits in 2013 would be $510 million to $1,200 million (2009 dollars) at a 3-percent discount rate) and $460 million to $1,100 million (2009 dollars) at a 7-percent discount rate.[11]

The final amendments are expected to reduce the overall emission reductions of the rules, primarily due to the changes to requirements for engines in remote areas. In addition to revising the anticipated emission reductions, the EPA has also updated the methodology used to calculate the co-benefits to be consistent with methods used in more recent rulemakings, which is summarized below and discussed in more detail in the CI and SI Final Reconsideration RIAs, the RIAs for this rulemaking. The EPA estimates the monetized co-benefits of the final amendments of the CI NESHAP in 2013 to be $770 million to $1,900 million (2010 dollars) at a 3-percent discount rate and $690 million to $1,700 million (2010 dollars) at a 7-percent discount rate. For SI engines, the EPA estimates the monetized co-benefits of the final amendments in 2013 to be $62 million to $150 million (2010 dollars) at a 3-percent discount rate and $55 million to $140 million (2010 dollars) at a 7-percent discount rate.

Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower co-benefits estimates are plausible, but most of the expert-based estimates fall between

[9] Since the June 7, 2012 reconsideration proposal, the EPA has made several updates to the approach used to estimate mortality and morbidity benefits, as demonstrated in the RIA for the PM NAAQS. Changes include applying the concentration-response functions from more recent epidemiology studies, adding some health endpoints, and updating population data. Although the EPA has not re-estimated the benefits for this rule by applying these changes, we anticipate that the rounded benefits estimated for this rule are unlikely to be very different than those provided here. Specifically, we anticipate that the changes that would likely lead to small increases in the benefits would likely be offset by changes that would likely lead to small decreases in the benefits. References for the RIA for the PM NAAQS are: (1) U.S. Environmental Protection Agency (U.S. EPA). 2012a. Regulatory Impact Analysis for the Proposed Revisions to the National Ambient Air Quality Standards for Particulate Matter. EPA–452/R–12–003. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. June. Available at *http://www.epa.gov/ttnecas1/regdata/RIAs/PMRIACombinedFile_Bookmarked.pdf*. (2) U.S. Environmental Protection Agency (U.S. EPA). 2012b. Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter. EPA–452/R–12–003. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. December. Available at *http://www.epa.gov/pm/2012/finalria.pdf*.

[10] U.S. Environmental Protection Agency. 2010. *Regulatory Impact Analysis (RIA) for Existing Stationary Compression Ignition Engines NESHAP: Final Draft.* Research Triangle Park, NC. February. *http://www.epa.gov/ttn/ecas/regdata/RIAs/CIRICENESHAPRIA2-17-0cleanpublication.pdf*.

[11] U.S. Environmental Protection Agency. 2010. *Regulatory Impact Analysis (RIA) for Existing Stationary Spark Ignition (SI) RICE NESHAP: Final Report.* Research Triangle Park, NC. August. *http://www.epa.gov/ttn/ecas/regdata/RIAs/riceriafinal.pdf*.

these two estimates.[12] A summary of the monetized co-benefits estimates for CI and SI engines at discount rates of 3-percent and 7-percent is in Table 6 of this preamble.

TABLE 6—SUMMARY OF THE MONETIZED $PM_{2.5}$ CO-BENEFITS FINAL AMENDMENTS TO THE NESHAP FOR STATIONARY CI AND SI ENGINES

[Millions of 2010 dollars] [a] [b]

Pollutant	Emission reductions (tons per year)	Total monetized co-benefits (3 percent discount)	Total monetized co-benefits (7 percent discount)
Original 2010 Final Rules [c]			
Stationary CI Engines:			
Total Benefits	2,844 $PM_{2.5}$, 27,395 VOC	$950 to $2,300	$860 to $2,100.
Stationary SI Engines:			
Total Benefits	96,479 NO_X, 30,907 VOC	$510 to $1,300	$470 to $1,100.
2010 Final Rules With These Final Amendments			
Stationary CI Engines:			
Directly emitted $PM_{2.5}$	2,818	$770 to $1,900	$690 to $1,700.
Stationary SI Engines:			
NO_X	9,648	$62 to $150	$55 to $140.

[a] All estimates are for the analysis year (2013) and are rounded to two significant figures so numbers may not sum across rows. The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as NO_X and directly emitted $PM_{2.5}$. It is important to note that the monetized co-benefits do not include reduced health effects from exposure to HAP, direct exposure to NO_2, exposure to ozone, ecosystem effects or visibility impairment.

[b] PM co-benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type.

[c] The benefits analysis for the 2010 final rules applied out-dated benefit-per-ton estimates compared to the updated estimates described in this preamble and reflected monetized co-benefits for VOC emissions, which limits direct comparability with the monetized co-benefits estimated for this final rule. In addition, these estimates have been updated from their original currency years to 2010$, so the rounded estimates for the 2010 final rules may not match the original RIAs.

These co-benefits estimates represent the total monetized human health benefits for populations exposed to less $PM_{2.5}$ in 2013 from controls installed to reduce air pollutants in order to meet this final rule. To estimate human health co-benefits of these rules, the EPA used benefit-per-ton factors to quantify the changes in $PM_{2.5}$-related health impacts and monetized benefits based on changes in directly emitted $PM_{2.5}$ and NO_X emissions. These benefit-per-ton factors were derived using the general approach and methodology laid out in Fann, Fulcher and Hubbell (2009).[13] This approach uses a model to convert emissions of $PM_{2.5}$ precursors into changes in ambient $PM_{2.5}$ levels and another model to estimate the changes in human health associated with that change in air quality, which are then divided by the emission reductions to create the benefit-per-ton estimates. However, for these rules, the EPA utilized air quality modeling of emissions in the ''Non-EGU Point other'' category because the EPA does not have modeling specifically for stationary engines.[14] [15] The primary difference between the estimates used in this analysis and the estimates reported in Fann, Fulcher and Hubbell (2009) is the air quality modeling data utilized. While the air quality data used in Fann, Fulcher and Hubbell (2009) reflects broad pollutant/source category combinations, such as all non-EGU stationary point sources, the air quality modeling data used in this analysis has narrower sector categories. In addition, the updated air quality modeling data reflects more recent emissions data (2005 rather than 2001) and has a higher spatial resolution (12 km rather than 36 km grid cells). The benefits methodology, such as health endpoints assessed, risk estimates applied, and valuation techniques applied did not change. As a result, the benefit-per-ton estimates presented herein better reflect the geographic areas and populations likely to be affected by this sector. However, these updated estimates still have similar limitations as all national-average benefit-per-ton estimates in that they reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions in this rulemaking, and they may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates or other local factors for any specific location.[16]

[12] Roman, *et al.*, 2008. *Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S.*, Environ. Sci. Technol., 42, 7, 2268–2274.

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

[14] U.S. Environmental Protection Agency. 2012. *Technical support document: Estimating the benefit per ton of reducing $PM_{2.5}$ precursors from other point sources.* Research Triangle Park, NC.

[15] Stationary engines are included in the other non-EGU point source category. If the affected stationary engines are more rural than the average of the non-EGU sources modeled, then it is possible that the benefits may be somewhat less than the EPA has estimated here. The TSD provides the geographic distribution of the air quality changes associated with this sector. It is important to emphasize that this modeling represents the best available information on the air quality impact on a per ton basis for these sources.

[16] To the extent that the $PM_{2.5}$ improvements achieved by the 2010 final rule would have been located in areas with lower average population density compared to the engines regulated under these amendments, there is a potential for the estimated loss in benefits to be overstated by the use of national-average benefit-per-ton estimates. For example, if only engines in areas with higher population density are regulated, this scenario should result in higher benefit-per-ton estimates than a scenario only regulating engines in areas with lower population density. It is important to

The EPA applies these national benefit-per-ton estimates calculated for this sector separately for directly emitted $PM_{2.5}$ and NO_X and multiply them by the corresponding emission reductions. The sector modeling does not provide estimates of the $PM_{2.5}$-related benefits associated with reducing VOC emissions, but these unquantified benefits are generally small compared to other $PM_{2.5}$ precursors. More information regarding the derivation of the benefit-per-ton estimates for this category is available in the Technical Support Document, which is available in the docket for this rulemaking.

These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type. The main $PM_{2.5}$ precursors affected by this final rule are directly emitted $PM_{2.5}$ and NO_X. Even though the EPA assumes that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. For example, directly emitted NO_X has a lower benefit-per-ton estimate than direct $PM_{2.5}$ because it does not form as much $PM_{2.5}$; thus, the exposure would be lower, and the monetized health benefits would be lower.

It is important to note that the magnitude of the $PM_{2.5}$ co-benefits is largely driven by the concentration response function for premature mortality. Experts have advised the EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. The EPA cites two key empirical studies, one based on the American Cancer Society cohort study [17] and the extended Six Cities cohort study.[18] In the RIA for the proposed reconsideration amendments rule, which is available in the docket, the EPA also includes benefits estimates derived from the expert judgments and other assumptions.

The EPA strives to use the best available science to support our benefits analyses. The EPA recognizes that interpretation of the science regarding air pollution and health is dynamic and evolving. After reviewing the scientific literature, the EPA has determined that the no-threshold model is the most appropriate model for assessing the mortality benefits associated with reducing $PM_{2.5}$ exposure. Consistent with this finding, the EPA has conformed the previous threshold sensitivity analysis to the current state of the PM science by incorporating a new "Lowest Measured Level" (LML) assessment in the RIA accompanying these rules. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, the EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

Most of the estimated PM-related co-benefits for these rules would accrue to populations exposed to higher levels of $PM_{2.5}$. For this analysis, policy-specific air quality data are not available due to time or resource limitations, and, thus, the EPA is unable to estimate the percentage of premature mortality associated with this specific rule's emission reductions at each $PM_{2.5}$ level. As a surrogate measure of mortality impacts, the EPA provides the percentage of the population exposed at each $PM_{2.5}$ level using the source apportionment modeling used to calculate the benefit-per-ton estimates for this sector. Using the Pope, *et al.* (2002) study, 77 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 7.5 micrograms per cubic meter ($\mu g/m^3$). Using the Laden, *et al.* (2006) study, 25 percent of the population is exposed above the LML of 10 $\mu g/m^3$. It is important to emphasize that we have high confidence in $PM_{2.5}$-related effects down to the lowest LML of the major cohort studies. This fact is important, because, as the EPA models avoided premature deaths among populations exposed to levels of $PM_{2.5}$, the EPA has lower confidence in levels below the LML for each study.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, the EPA believes the benefit analysis for these rules provides a reasonable indication of the expected health benefits of the rulemaking under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2006 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA because the EPA lacks the necessary air quality input and monitoring data to run the benefits model. In addition, the EPA has not conducted air quality modeling for these rules, and using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2006 $PM_{2.5}$ NAAQS benefits analysis [19] provides an indication of the sensitivity of our results to various assumptions.

It should be noted that the monetized co-benefits estimates provided above do not include benefits from several important benefit categories, including exposure to HAP, NO_X, ozone, as well as ecosystem effects and visibility impairment. Although the EPA does not have sufficient information or modeling available to provide monetized estimates for these amendments, the EPA includes a qualitative assessment of these unquantified benefits in the RIAs for these final amendments.

For more information on the benefits analysis, please refer to the CI and SI RIAs for these amendments, which are available in the docket.

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

The EPA does not anticipate any significant non-air health, environmental or energy impacts as a result of these final amendments.

V. Statutory and Executive Order Reviews

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

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the

note that the benefit-per-ton estimates that EPA applied in this assessment reflect pollution transport as well as a variety of emission source locations, including areas with high and low population density. Without information regarding the specific location of the engines affected by the 2010 final rule and the amendments, it is not possible to be more precise regarding the true magnitude of the loss in benefits.

[17] Pope, *et al.*, 2002. *Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution.* Journal of the American Medical Association 287:1132–1141.

[18] Laden, *et al.*, 2006. *Reduction in Fine Particulate Air Pollution and Mortality.* American Journal of Respiratory and Critical Care Medicine 173: 667–672.

[19] U.S. Environmental Protection Agency, 2006. *Proposed amendments Regulatory Impact Analysis: $PM_{2.5}$ NAAQS.* Prepared by Office of Air and Radiation. October. Available on the Internet at *http://www.epa.gov/ttn/ecas/ria.html.*

economy of $100 million or more. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action.

A summary of the monetized benefits, compliance costs and net benefits for the 2010 rule with the final amendments to the stationary CI engines NESHAP at discount rates of 3 percent and 7 percent is in Table 7 of this preamble. The summary for stationary SI engines is included in Table 8 of this preamble. OMB Circular A–4 recommends that analysis of a change in an existing regulatory program use a baseline that assumes ''no change'' in the existing regulation. For purposes of this final rule, however, the EPA has decided that it is appropriate to assume a baseline in which the original 2010 rule did not exist. The EPA feels that this baseline is appropriate because full implementation of this final rule has not taken place as of yet (it will take place in 2013). In addition, this assumption is consistent with the baseline definition applied in the proposed NESHAP for Industrial, Commercial, and Institutional Boilers (76 FR 80532) and NSPS for Commercial/Industrial Solid Waste Incineration Units (76 FR 80452). We have not re-estimated the benefits from the proposal for this final rule because the emission reductions have not changed since the reconsideration proposal. Since the June 7, 2012, reconsideration proposal, we have updated the epidemiology studies used to calculate mortality and morbidity benefits in the PM NAAQS proposal RIA.[20] These updates would reduce the monetized benefits estimated for the RICE NESHAP reconsideration by less than 4 percent.

TABLE 7—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS AND NET BENEFITS FOR THE 2010 RULE WITH THE FINAL AMENDMENTS TO THE STATIONARY CI ENGINE NESHAP IN 2013

[Millions of 2010 dollars][a]

	3-Percent discount rate	7-Percent discount rate
Total Monetized Benefits[b]	$770 to $1,900	$690 to $1,700.
Total Compliance Costs[c]	$373	$373.
Net Benefits	$400 to $1,500	$320 to $1,300.
Non-Monetized Benefits	Health effects from exposure to HAP. Health effects from direct exposure to NO_2 and ozone. Health effects from $PM_{2.5}$ exposure from VOC. Ecosystem effects. Visibility impairment.	

[a] All estimates are for the implementation year (2013) and are rounded to two significant figures.
[b] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as NO_X and directly emitted $PM_{2.5}$. Co-benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type.
[c] The engineering compliance costs are annualized using a 7-percent discount rate.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS AND NET BENEFITS FOR THE 2010 RULE WITH THE FINAL AMENDMENTS TO THE STATIONARY SI ENGINE NESHAP IN 2013

[Millions of 2010 dollars][a]

	3-Percent discount rate	7-Percent discount rate
Total Monetized Benefits[b]	$62 to $150	$55 to $140.
Total Compliance Costs[c]	$115	$115.
Net Benefits	$ −53 to $35	$ −60 to $25.
Non-Monetized Benefits	Health effects from exposure to HAP. Health effects from direct exposure to NO_2 and ozone. Health effects from $PM_{2.5}$ exposure from VOC. Ecosystem effects. Visibility impairment.	

[a] All estimates are for the implementation year (2013) and are rounded to two significant figures.
[b] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as NO_X and directly emitted $PM_{2.5}$. Co-benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type.
[c] The engineering compliance costs are annualized using a 7-percent discount rate.

For more information on the cost-benefit analysis, please refer to the RIA for these final amendments, which is available in the docket for this rulemaking.

[20] U.S. Environmental Protection Agency (U.S. EPA). 2012. Regulatory Impact Analysis for the Proposed Revisions to the National Ambient Air Quality Standards for Particulate Matter. EPA–452/R–12–003. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. June. Available at *http://www.epa.gov/ttnecas1/regdata/RIAs/PMRIACombinedFile_Bookmarked.pdf.*

B. Paperwork Reduction Act

The information collection requirements in this final rule for stationary SI RICE have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The information collection requirements are not enforceable until OMB approves them.

As discussed in this preamble to this final action, there are reporting requirements that will begin in 2016. Owners and operators of emergency stationary engines that operate or are contractually obligated to be available for more than 15 hours per year for emergency demand response must document their operation in annual reports to the EPA. These reports are necessary to enable EPA or States to identify affected facilities that may not be in compliance with the requirements. The burden of this reporting requirement is not included in the ICR burden estimate because it is after the first 3 years after which sources must begin complying with the rule. The reporting burden beginning in 2016 would only be included starting with the first ICR renewal. The EPA anticipates that in most cases, the entity that dispatches the engines to operate, such as the curtailment service provider or utility, will report the information to EPA on behalf of the facility that owns the engine. Thus, the burden of the reporting requirement will likely be on the entities that dispatch the engines. The number of entities is uncertain, but the EPA estimates that approximately 446 local utilities would engage in the reporting requirement. The EPA estimates that each utility would spend approximately 16 hours per year reporting the information to the EPA. As of June 2012, the total compensation for management/professional staff was $51.23 per hour. Adjusting this compensation rate by applying an overhead rate of 167 percent yields a total wage rate of $85.60 per hour.[21] This results in an estimated burden of 7,136 hours at a cost of $611,000 per year, beginning in the year 2015. For curtailment service providers, the EPA estimated the burden of the requirement to be 1,000 hours at a cost of $60,000 in the first year of implementation, 2015, and 250 hours at a cost of $15,000 in subsequent years (using a wage rate of $60 per hour). Using an estimated number of 70 curtailment service providers nationwide that are operating engines for emergency demand response, the burden for curtailment service providers would be 70,000 hours at a cost of $4.2 million in the first year of implementation, 2015, and 17,500 hours at a cost of $1 million in subsequent years. Summing the totals for the cooperatives and curtailment service providers yields a total of 77,136 labor hours at a cost of $4.8 million in the first year that reporting is required, 2015, and 24,636 labor hours at a cost of $1.7 million in subsequent years.

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

The OMB has previously approved the information collection requirements contained in the 2010 RICE NESHAP final rulemaking, including those for stationary CI RICE, under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control number 2060–0548. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

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

For purposes of assessing the impacts of this rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. The SBA defines a small business in terms of the maximum employment, annual sales, or annual energy-generating capacity (for electricity generating units—EGUs) of the owning entity. As mentioned earlier in this preamble, facilities across several industries use affected CI and SI stationary RICE; therefore, a number of size standards are utilized in this analysis.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The small entities directly regulated by this final rule are those in the 15 industries identified in the 6-digit NAICS code represented in this analysis; the employment size standard (where it applies) varies from 500 to 1,000 employees. The annual sales standard (where it applies) is as low as 0.75 million dollars and as high as 33.5 million dollars. In addition, for the electric power generation industry, which is one of the affected industries, the small business size standard is an ultimate parent entity defined as having a total electric output of 4 million megawatt-hours in the previous fiscal year. We have determined that the percentage of small entities impacted by this final rule having annualized costs of greater than 1 percent of their sales is less than 2 percent of all affected small entities according to the small entity analysis.

Although the final reconsideration rule will not have a significant economic impact on a substantial number of small entities, the EPA nonetheless tried to reduce the impact of this rule on small entities. When developing the revised standards, the EPA took special steps to ensure that the burdens imposed on small entities were minimal. The EPA conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. In addition, as mentioned earlier in this preamble, the EPA is reducing the regulatory requirements for a variety of area sources affected under each of the RICE rules with amendments to the final RICE rules promulgated in 2010.

For more information on the small entity impacts associated with this rulemaking, please refer to the Economic Impact and Small Business Analyses in the public docket. These analyses can be found in the RIA for each of the rules affected by this action.

D. Unfunded Mandates Reform Act

This rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. The EPA is finalizing management

[21] *http://www.bls.gov/news.release/ecec.t05.htm.*

practices for certain existing engines located at area sources and is finalizing amendments that will provide owners and operators with alternative and less expensive compliance demonstration methods. As a result of these changes, the EPA anticipates a substantial reduction in the cost burden associated with this rule. Thus, this final rule is not subject to the requirements of sections 202 or 205 of UMRA.

This final rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. The changes being finalized in this action by the agency will mostly affect stationary engine owners and operators and will not affect small governments. These final amendments will lead to a reduction in the cost burden.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This action primarily affects private industry, and does not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicited comment on the proposed action from state and local officials.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action. In the spirit of Executive Order 13175, and consistent with the EPA policy to promote communications between the EPA and tribal governments, the EPA has conducted outreach to tribal governments by providing information on the rule during National Tribal Air Association/EPA Policy Calls.

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

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

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

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. This action reduces the burden of the rule on owners and operators of stationary engines by providing less burdensome compliance demonstration methods to owners and operators and greater flexibility in the operation of emergency engines. As a result of these changes, the EPA anticipates a substantial reduction in the cost burden associated with this rule.

I. National Technology Transfer and Advancement Act

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

This rulemaking involves technical standards. The EPA has decided to use EPA Method 25A of 40 CFR part 60, appendix A. While the agency identified two voluntary consensus standards as being potentially applicable, the EPA has decided not to use them in this rulemaking. The two candidate voluntary consensus standards, ISO 14965:2000(E) and EN 12619 (1999), identified would not be practical due to lack of equivalency, documentation, validation data and other important technical and policy considerations. The search and review results have been documented and are placed in the docket for this final rule.

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

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

The EPA has concluded that it is not feasible to determine whether there would be disproportionately high and adverse human health or environmental effects on minority, low income or indigenous populations from this final rule, as the EPA does not have specific information about the location of the stationary RICE affected by this final rule. The EPA has taken steps to reduce the impact of the final changes for SI engines by limiting the subcategory for remote engines to those that are not in populated areas.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective on April 1, 2013.

List of Subjects

40 CFR Part 60

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

40 CFR Part 63

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

Dated: January 14, 2013.

Lisa P. Jackson,

Administrator.

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

PART 60—[AMENDED]

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

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

Subpart A—[Amended]

■ 2. Section 60.17 is amended by adding paragraph (r) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(r) The following material is available from the North American Electric Reliability Corporation, 3353 Peachtree Road NE., Suite 600, North Tower, Atlanta, GA 30326, *http://www.nerc.com*, and is available at the following Web site: *http://www.nerc.com/files/EOP-002-3_1.pdf.*

(1) North American Electric Reliability Corporation, Reliability Standards for the Bulk of Electric Systems of North America, Reliability Standard EOP–002–3, Capacity and Energy Emergencies, updated November 19, 2012, IBR approved for §§ 60.4211(f) and 60.4243(d).

(2) [Reserved]

Subpart IIII—[Amended]

■ 3. Section 60.4207 is amended by revising paragraph (b) to read as follows:

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

* * * * *

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

* * * * *

■ 4. Section 60.4211 is amended by revising paragraph (f) to read as follows:

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

* * * * *

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP–002–3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP–002–3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local

transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

* * * * *

■ 5. Section 60.4214 is amended by adding paragraph (d) to read as follows:

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

* * * * *

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

■ 6. Section 60.4219 is amended by revising the definition of "Emergency stationary internal combustion engine" to read as follows:

§ 60.4219 What definitions apply to this subpart?

* * * * *

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(2)(ii) or (iii) and § 60.4211(f)(3)(i).

* * * * *

Subpart JJJJ—[Amended]

■ 7. Section 60.4231 is amended by revising paragraphs (b) through (d) to read as follows:

§ 60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?

* * * * *

(b) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE with a maximum engine power greater than 25 HP and less than 130 HP that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cubic centimeters (cc) that use gasoline to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(c) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum

engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc that are rich burn engines that use LPG to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(d) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) under the voluntary manufacturer certification program described in this subpart must certify those engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers who choose to certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP (except gasoline and rich burn engines that use LPG), must certify those engines to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc (except gasoline and rich burn engines that use LPG) to the certification emission standards for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate. For stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) manufactured prior to January 1, 2011, manufacturers may choose to certify these engines to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP.

* * * * *

■ 8. Section 60.4243 is amended by revising paragraph (d) to read as follows:

§ 60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

* * * * *

(d) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (d)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (d)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (d)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (d)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP–002–3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP–002–3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (d)(2) of this section. Except as provided in paragraph (d)(3)(i) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

* * * * *

■ 9. Section 60.4245 is amended by adding paragraph (e) to read as follows:

§ 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

* * * * *

(e) If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates or is contractually

obligated to be available for more than 15 hours per calendar year for the purposes specified in § 60.4243(d)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4243(d)(3)(i), you must submit an annual report according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 60.4243(d)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 60.4243(d)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 60.4243(d)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in § 60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4243(d)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

■ 10. Section 60.4248 is amended by revising the definition of "Emergency stationary internal combustion engine" to read as follows:

§ 60.4248 What definitions apply to this subpart?

* * * * *

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4243(d) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4243(d), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4243(d).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4243(d)(2)(ii) or (iii) and § 60.4243(d)(3)(i).

* * * * *

■ 11. Table 2 to Subpart JJJJ of part 60 is revised to read as follows:

As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load:

TABLE 2 TO SUBPART JJJJ OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to § 60.4244.	a. limit the concentration of NO_X in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A or ASTM Method D6522–00 (Reapproved 2005).[a e]	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00 (Reapproved 2005).[a e]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60, appendix A.	
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(c) Measurements to determine moisture must be made at the same time as the measurementfor NO_X concentration.

TABLE 2 TO SUBPART JJJJ OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each	Complying with the requirement to	You must	Using	According to the following requirements
		v. Measure NO_X at the exhaust of the stationary internal combustion engine.	(5) Method 7E of 40 CFR part 60, appendix A, Method D6522–00 (Reapproved 2005)[a e], Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(d) Results of this test consist of the average of the three 1-hour or longer runs.
	b. limit the concentration of CO in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A or ASTM Method D6522–00 (Reapproved 2005).[a e]	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00 (Reapproved 2005).[a e]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for CO concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60, appendix A.	
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(c) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.
		v. Measure CO at the exhaust of the stationary internal combustion engine.	(5) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (Reapproved 2005)[a e], Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(d) Results of this test consist of the average of the three 1-hour or longer runs.
	c. limit the concentration of VOC in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00 (Reapproved 2005).[a e]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for VOC concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60, appendix A.	
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(c) Measurements to determine moisture must be made at the same time as the measurementfor VOC concentration.

TABLE 2 TO SUBPART JJJJ OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each	Complying with the requirement to	You must	Using	According to the following requirements
		v. Measure VOC at the exhaust of the stationary internal combustion engine.	(5) Methods 25A and 18 of 40 CFR part 60, appendix A, Method 25A with the use of a methane cutter as described in 40 CFR 1065.265, Method 18 of 40 CFR part 60, appendix A,[c d] Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(d) Results of this test consist of the average of the three 1-hour or longer runs.

[a] You may petition the Administrator for approval to use alternative methods for portable analyzer.
[b] You may use ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses, for measuring the O_2 content of the exhaust gas as an alternative to EPA Method 3B.
[c] You may use EPA Method 18 of 40 CFR part 60, appendix, provided that you conduct an adequate presurvey test prior to the emissions test, such as the one described in OTM 11 on EPA's Web site (*http://www.epa.gov/ttn/emc/prelim/otm11.pdf*).
[d] You may use ASTM D6420–99 (2004), Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry as an alternative to EPA Method 18 for measuring total nonmethane organic.
[e] Incorporated by reference, see 40 CFR 60.17.

PART 63—[AMENDED]

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

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

Subpart A—[Amended]

■ 13. Section 63.14 is amended by:
■ a. Revising paragraphs (b)(28) and (b)(54);
■ b. Adding paragraph (d)(10);
■ c. Revising paragraph (i)(1); and
■ d. Adding paragraph (s) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) * * *

(28) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (Approved October 1, 2004), IBR approved for §§ 60.485(g), 60.485a(g), 63.457(b), 63.772(a) and (e), 63.1282(a) and (d), 63.2351(b), 63.2354(b) and table 8 to subpart HHHHHHH of this part.

* * * * *

(54) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved 2003, IBR approved for §§ 63.457, 63.1349, table 4 to subpart DDDD of this part, table 4 to subpart ZZZZ of this part, and table 8 to subpart HHHHHHH of this part.

* * * * *

(d) * * *

(10) Alaska Statute, Title 42—Public Utilities And Carriers And Energy Programs, Chapter 45—Rural and Statewide Energy Programs, Article 1, Power Assistance Programs, Sec. 42.45.045. Renewable energy grant fund and recommendation program, effective May 3, 2012, available at *http://www.legis.state.ak.us/basis/folio.asp*, IBR approved for § 63.6675.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus], issued August 31, 1981, IBR approved for §§ 63.309(k), 63.457(k), 63.772(e) and (h), 63.865(b), 63.1282(d) and (g), 63.3166(a), 63.3360(e), 63.3545(a), 63.3555(a), 63.4166(a), 63.4362(a), 63.4766(a), 63.4965(a), 63.5160(d), 63.9307(c), 63.9323(a), 63.11148(e), 63.11155(e), 63.11162(f), 63.11163(g), 63.11410(j), 63.11551(a), 63.11646(a), 63.11945, table 5 to subpart DDDDD of this part, table 4 to subpart JJJJJ of this part, table 5 to subpart UUUUU of this part, and table 1 to subpart ZZZZZ of this part.

* * * * *

(s) The following material is available from the North American Electric Reliability Corporation, 3353 Peachtree Road NE., Suite 600, North Tower, Atlanta, GA 30326, *http://www.nerc.com*, and is available at the following Web site: *http://www.nerc.com/files/EOP-002-3_1.pdf*.

(1) North American Electric Reliability Corporation, Reliability Standards for the Bulk of Electric Systems of North America, Reliability Standard EOP–002–3, Capacity and Energy Emergencies, updated November 19, 2012, IBR approved for § 63.6640(f).

(2) [Reserved]

Subpart ZZZZ—[Amended]

■ 14. Section 63.6585 is amended by adding paragraph (f) to read as follows:

§ 63.6585 Am I subject to this subpart?

* * * * *

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

■ 15. Section 63.6590 is amended by revising paragraphs (b)(1)(i) and (b)(3)(iii) and removing paragraphs (b)(3)(vi) through (viii).

The revisions read as follows.

§ 63.6590 What parts of my plant does this subpart cover?

* * * * *

(b) * * *

(1) * * *

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

* * * * *

(3) * * *

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

* * * * *

■ 16. Section 63.6595 is amended by revising paragraph (a)(1) to read as follows:

§ 63.6595 When do I have to comply with this subpart?

(a) * * *

(1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

* * * * *

■ 17. Section 63.6602 is revised to read as follows:

§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

■ 18. Section 63.6603 is amended by:

■ a. Revising the section heading;

■ b. Revising paragraph (a);

■ c. Revising paragraph (b); and

■ d. Adding paragraphs (c) through (f).

The revisions and addition read as follows:

§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

* * * * *

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the

engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

■ 19. Section 63.6604 is revised to read as follows:

§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

■ 20. Section 63.6605 is amended by revising paragraph (a) to read as follows:

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

* * * * *

■ 21. Section 63.6620 is amended by revising paragraphs (b), (d) and (e) to read as follows:

§ 63.6620 What performance tests and other procedures must I use?

* * * * *

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

* * * * *

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

compliance with the percent reduction requirement:

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_O = \frac{0.209\ F_d}{F_C} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq.\ 3)$$

measurement data to 15 percent O_2, as follows:

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

* * * * *

■ 22. Section 63.6625 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising the first sentence in paragraph (b) introductory text;

■ c. Revising paragraph (b)(1)(iv);

■ d. Revising paragraph (e)(6),

■ e. Revising paragraph (g),

■ f. Revising paragraph (i); and

■ g. Revising paragraph (j).

The revisions read as follows:

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

* * * * *

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. * * *

(1) * * *

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

* * * * *

(e) * * *

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

* * * * *

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

* * * * *

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20

percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

■ 23. Section 63.6630 is amended by revising the section heading and paragraph (a) and adding paragraphs (d) and (e) to read as follows:

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

* * * * *

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

■ 24. Section 63.6640 is amended by:

■ a. Revising the section heading;

■ b. Revising paragraph (a);

■ c. Adding paragraph (c); and

■ d. Revising paragraph (f).

The revisions and addition read as follows:

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

* * * * *

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

* * * * *

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP–002–3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP–002–3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

■ 25. Section 63.6645 is amended by adding paragraph (i) to read as follows:

§ 63.6645 What notifications must I submit and when?

* * * * *

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

■ 26. Section 63.6650 is amended by adding paragraph (h) to read as follows:

§ 63.6650 What reports must I submit and when?

* * * * *

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 63.13.

■ 27. Section 63.6655 is amended by revising paragraph (f) introductory text to read as follows:

§ 63.6655 What records must I keep?

* * * * *

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

* * * * *

■ 28. Section 63.6675 is amended by:

■ a. Adding in alphabetical order the definition of *Alaska Railbelt Grid;*

■ b. Adding in alphabetical order the definition of *Backup power for renewable energy;*

■ c. Revising the definition of *Emergency stationary RICE;* and

■ d. Adding in alphabetical order the definition of *Remote stationary RICE.*

The additions and revision read as follows.

§ 63.6675 What definitions apply to this subpart?

* * * * *

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

* * * * *

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

* * * * *

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(2)(ii) or (iii) and § 63.6640(f)(4)(i) or (ii).

* * * * *

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

* * * * *

■ 29. Table 1b to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed

4SRB stationary RICE >500 HP located at a major source of HAP emissions:

TABLE 1b TO SUBPART ZZZZ OF PART 63—OPERATING LIMITATIONS FOR EXISTING, NEW, AND RECONSTRUCTED SI 4SRB STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	Comply with any operating limitations approved by the Administrator.

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

■ 30. Table 2b to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

TABLE 2b TO SUBPART ZZZZ OF PART 63—OPERATING LIMITATIONS FOR NEW AND RECONSTRUCTED 2SLB AND CI STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS, NEW AND RECONSTRUCTED 4SLB STATIONARY RICE ≥250 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS, EXISTING CI STATIONARY RICE >500 HP

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.

TABLE 2b TO SUBPART ZZZZ OF PART 63—OPERATING LIMITATIONS FOR NEW AND RECONSTRUCTED 2SLB AND CI STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS, NEW AND RECONSTRUCTED 4SLB STATIONARY RICE ≥250 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS, EXISTING CI STATIONARY RICE >500 HP—Continued

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

■ 31. Table 2c to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

TABLE 2c TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING COMPRESSION IGNITION STATIONARY RICE LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS AND EXISTING SPARK IGNITION STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE [1].	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP.	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP.	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	
4. Non-Emergency, non-black start CI stationary RICE 300>HP≤500.	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP.	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	

TABLE 2c TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING COMPRESSION IGNITION STATIONARY RICE LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS AND EXISTING SPARK IGNITION STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS—Continued

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP.	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500.	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500.	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500.	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

■ 32. Table 2d to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

TABLE 2d TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING STATIONARY RICE LOCATED AT AREA SOURCES OF HAP EMISSIONS

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP.	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500.	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP.	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	

TABLE 2d TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING STATIONARY RICE LOCATED AT AREA SOURCES OF HAP EMISSIONS—Continued

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE.	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP.	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year.	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP.	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year.	Install NSCR to reduce HAP emissions from the stationary RICE.	

TABLE 2d TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING STATIONARY RICE LOCATED AT AREA SOURCES OF HAP EMISSIONS—Continued

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

■ 33. Table 3 to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

TABLE 3 TO SUBPART ZZZZ OF PART 63—SUBSEQUENT PERFORMANCE TESTS

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources.	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semi-annually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources.	Reduce formaldehyde emissions	Conduct subsequent performance tests semi-annually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources.	Limit the concentration of formaldehyde in the stationary RICE exhaust.	Conduct subsequent performance tests semi-annually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE.	Limit or reduce CO emissions and not using a CEMS.	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE.	Limit or reduce CO emissions and not using a CEMS.	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

■ 34. Table 4 to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

TABLE 4 TO SUBPART ZZZZ OF PART 63. REQUIREMENTS FOR PERFORMANCE TESTS

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE.	a. reduce CO emissions.	i. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (Reapproved 2005).[a c]	(a) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device.	(1) ASTM D6522–00 (Reapproved 2005)[a b c] or Method 10 of 40 CFR part 60, appendix A.	(a) The CO concentration must be at 15 percent O_2, dry basis.

TABLE 4 TO SUBPART ZZZZ OF PART 63. REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE.	a. reduce formaldehyde emissions.	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	(a) sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (Reapproved 2005).[a]	(a) measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device.	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[a] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device.	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A.	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE.	a. limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	(a) if using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (Reapproved 2005).[a]	(a) measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[a] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the stationary RICE.	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005),[a c] Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.[a]	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a] Incorporated by reference, see 40 CFR 63.14. You may also obtain copies from University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.
[b] You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.
[c] ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

■ 35. Table 5 to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

TABLE 5 TO SUBPART ZZZZ OF PART 63—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS, OPERATING LIMITATIONS, AND OTHER REQUIREMENTS

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS.	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Reduce CO emissions and not using oxidation catalyst.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Limit the concentration of CO, and not using oxidation catalyst.	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Limit the concentration of CO, and using a CEMS.	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and

TABLE 5 TO SUBPART ZZZZ OF PART 63—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS, OPERATING LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and not using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP.	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.

TABLE 5 TO SUBPART ZZZZ OF PART 63—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS, OPERATING LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP.	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

■ 36. Table 6 to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP.	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP.	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP.	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS.	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and using NSCR.	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and not using NSCR.	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP.	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE.	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE.	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst.	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE.	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst.	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP.	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst.	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP.	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst.	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

■ 37. Table 7 to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in § 63.6650, you must comply with the following requirements for reports:

TABLE 7 TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR REPORTS

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP.	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in § 63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in § 63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or	i. Semiannually according to the requirements in § 63.6650(b).
		c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4).	i. Semiannually according to the requirements in § 63.6650(b).

TABLE 7 TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR REPORTS—Continued

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in § 63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year.	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in § 63.6650(b)(1)–(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in § 63.6640(f)(4)(ii).	Report	a. The information in § 63.6650(h)(1).	i. annually according to the requirements in § 63.6650(h)(2)–(3).

■ 38. Table 8 to Subpart ZZZZ of Part 63 is amended by:

■ a. Revising the entry for § 63.8(c)(1)(i);

■ b. Revising the entry for § 63.8(c)(1)(iii); and

■ c. Revising the entry for § 63.10(b)(1) to read as follows:

As stated in § 63.6665, you must comply with the following applicable general provisions.

TABLE 8 TO SUBPART ZZZZ OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART ZZZZ

General Provisions Citation	Subject of Citation	Applies to Subpart	Explanation
* * *	* * *	* * *	
§ 63.8(c)(1)(i)	Routine and predictable SSM	No	
* * *	* * *	* * *	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements.	No	
* * *	* * *	* * *	
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
* * *	* * *	* * *	

■ 39. Appendix A to Subpart ZZZZ of Part 63 is added to read as follows:

Appendix A—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630–08–0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782–44–7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO_2 are two gas species that have

been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ± 5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2. When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the "sample conditioning phase" once per minute until constant readings are obtained. Then begin the "measurement data phase" and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the "measurement data phase" readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ± 10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ± 3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ± 3 percent of the up-scale gas value or ± 1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ± 0.3 percent O_2 for the O_2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this ''sample conditioning phase'' once per minute until readings are constant for at least two minutes. Then begin the ''measurement data phase'' and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the ''refresh phase'' by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the ''measurement data phase'' readings from the reported standard gas value must be less than or equal to ± 5 percent or ± 1 ppm for CO or ± 0.5 percent O_2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single ''measurement data phase'' reading must be less than or equal to ± 2 percent or ± 1 ppm for CO or ± 0.5 percent O_2, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the ''measurement data phase''.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the ''measurement data phase''. The maximum allowable deviation from the mean for each of the individual readings is ± 2 percent, or ± 1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ± 2 percent *or ± 1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed*).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO_2 interference response should be less than or equal to ± 5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average ''measurement data phase'' CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ± 3 percent or ± 1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) ''Development of an Electrochemical Cell Emission Analyzer Test Protocol'', Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) ''Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers'', EMC Conditional Test Protocol 30 (CTM–30), Gas Research Institute Protocol GRI–96/0008, Revision 7, October 13, 1997.

(3) ''ICAC Test Protocol for Periodic Monitoring'', EMC Conditional Test Protocol 34 (CTM–034), The Institute of Clean Air Companies, September 8, 1999.

(4) ''Code of Federal Regulations'', Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1–4; 10.

TABLE 1: APPENDIX A—SAMPLING RUN DATA.

Facility_____ Engine I.D._____ Date_____

Run Type: ..... (__) (__) (__) (__)
(X) ..... Pre-Sample Calibration Stack Gas Sample Post-Sample Cal. Check Repeatability Check

Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO	.....	.....	.....
.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
Sample Cond. Phase	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
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Measurement Data Phase ..	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
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Part V

Environmental Protection Agency

40 CFR Part 63

National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0058; FRL–9676–8]

RIN 2060–AR13

National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; notice of final action on reconsideration.

SUMMARY: In this action the EPA is taking final action on its reconsideration of certain issues in the emission standards for the control of hazardous air pollutants from new and existing industrial, commercial, and institutional boilers and process heaters at major sources of hazardous air pollutants, which were issued under section 112 of the Clean Air Act. As part of this action, the EPA is making technical corrections to the final rule to clarify definitions, references, applicability and compliance issues raised by petitioners and other stakeholders affected by this rule. On March 21, 2011, the EPA promulgated national emission standards for this source category. On that same day, the EPA also published a notice announcing its intent to reconsider certain provisions of the final rule. Following these actions, the Administrator received several petitions for reconsideration. After consideration of the petitions received, on December 23, 2011, the EPA proposed revisions to certain provisions of the March 21, 2011, final rule, and requested public comment on several provisions of the final rule. The EPA is now taking final action on the proposed reconsideration.

DATES: The May 18, 2011 (76 FR28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) is lifted January 31, 2013. The amendments in this rule to 40 CFR part 63, subpart DDDDD are effective as of April 1, 2013.

ADDRESSES: The EPA established a single docket under Docket ID No. EPA–HQ–OAR–2002–0058 for this action. 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 Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Jim Eddinger, 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) 541–5426; Fax number (919) 541–5450; Email address: *eddinger.jim@epa.gov*.

SUPPLEMENTARY INFORMATION:

Executive Summary

Purpose of This Regulatory Action

The EPA is taking final action on its proposed reconsideration of certain provisions of its March 21, 2011, final rule that established standards for new and existing industrial, commercial, and institutional boilers and process heaters at major sources of hazardous air pollutants. Section 112(d) of the CAA requires the EPA to regulate HAP from major stationary sources based on the performance of MACT. Section 112(h) of the CAA allows the EPA to establish work practice standards in lieu of numerical emission limits only in cases where the agency determines that it is not feasible to prescribe or enforce an emission standard, including circumstances in which the agency determines that the application of measurement methodology is not practicable due to technological and economic limitations. The EPA is revising certain MACT standards established in March 2011 for boilers and process heaters, including standards for CO—as a surrogate for organic HAP; HCl—as a surrogate for acid gas HAP; Hg; TSM or filterable PM—as a surrogate for non-Hg metallic HAP; and dioxin/furan.

This final rule amends certain provisions of the final rule issued by the EPA on March 21, 2011. The EPA delayed the effective date of the 2011 rule in a May 18, 2011, notice, but that delay notice was vacated by the U.S. District Court for the District of Columbia on January 9, 2012, and the March 2011 final rule was, therefore, in effect until publication of this action.

Summary of Major Reconsideration Provisions

In general, this final rule requires facilities classified as major sources of HAP with affected boilers or process heaters to reduce emissions of harmful toxic air emissions from these combustion sources. This will improve air quality and protect public health in communities where these facilities are located.

Recognizing the diversity of this source category and the multiple sectors of the economy this final rule effects, the EPA is revising certain subcategories for boilers and process heaters in this action that were established in the March 2011 final rule, based on the design of the combustion equipment. These revisions result in 19 subcategories for the boilers and process heaters source category. Numerical emission limits are established for most of the subcategories for five pollutants, CO, HCl, Hg, and PM or TSM. The review of existing data and consideration of new data have resulted in changes to some of the emission limits contained in the March 2011 final rule. Overall, for both new and existing affected units, about 30 percent of the emission limits are more stringent, half are less stringent, and 20 percent unchanged as compared to the March 2011 final rule. Also, based on its review and analysis of new data submissions, the EPA is establishing an alternative emission standard for CO, based on CEMS data for several subcategories with CO CEMS data available. This alternative standard is based on a 30-day rolling average for subcategories for which sufficient CEMS data were available for more than a 30-day period, or a 10-day rolling average for subcategories for which CEMS data were available for less than a 30-day period, and provides additional compliance flexibility to sources. All of the subcategories are subject to periodic tune-up work practices for dioxin/furan emissions.

The compliance dates for the rule are January 31, 2016, for existing sources and, January 31, 2013, or upon startup, whichever is later, for new sources. New sources are defined as sources that began operation on or after June 4, 2010.

Costs and Benefits

The final rule affects 1,700 existing major source facilities with an estimated 14,136 boilers and process heaters and the EPA projects an additional 1,844 new boilers and process heaters to be subject to this final rule over the next 3

years. This final rule affects multiple sectors of the economy including small entities. Table 1 summarizes the costs and benefits associated with this final rule. A more detailed discussion of the costs and benefits of this final rule is provided in section VI of this preamble.

TABLE 1—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Total Monetized Benefits [2]	$27,000 to $67,000	$25,000 to $61,000.
Total Social Costs [3]	$1,400 to $1,600	$1,400 to $1,600.
Net Benefits	$26,000 to $65,000	$23,000 to $59,000.
Non-monetized Benefits	Health effects from exposure to HAP (39,000 tons of HCl, 500 tons of HF, 3,100 to 5,300 pounds of Hg and 2,500 tons of other metals). Health effects from exposure to other criteria pollutants (180,000 tons of CO and 572,000 tons of SO_2). Ecosystem effects. Visibility impairment.	

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures.

[2] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as directly emitted particles, SO_2, and NO_X and reducing exposure to ozone through reductions of VOC. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Monetized benefits are shown as a range from Pope et al. (2002) to Laden et al. (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to support the development of differential effects estimates by particle type. These estimates include the energy disbenefits valued at $24 million (using the 3 percent discount rate), which do not change the rounded totals. CO_2-related disbenefits were calculated using the "social cost of carbon," which is discussed further in the RIA.

[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

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

ACC American Chemistry Council
ACCCI American Coke and Coal Chemicals Institute
AF&PA American Forest and Paper Association
AHFA American Home Furnishings Alliance
AISI American Iron and Steel Institute
AMP American Municipal Power Inc.
AIE Alliance for Industrial Efficiency
APCD air pollution control devices
API American Petroleum Institute
AIF Auto Industry Forum
BFG Blast furnace gas
BLDS Bag leak detection system
BCSE The Business Council for Sustainable Energy
CIBO Council of Industrial Boiler Owners
CO Carbon monoxide
CO_2 Carbon dioxide
CEMS Continuous emissions monitoring system
CEG Citizens Energy Group
CAA Clean Air Act
CFR Code of Federal Regulations
CPMS Continuous parameter monitoring system
CMI CraftMaster Manufacturing Inc.
ERT Electronic Reporting Tool
ESP Electrostatic precipitator
EPA Environmental Protection Agency
FBC Fluidized bed combustion
FR Federal Register
FSI Florida Sugar Industry
GPSP Great Plains Synfuels Plant
HAP Hazardous air pollutants
HBES Health-based emissions standard
HF Hydrogen fluoride
Hg Mercury
HCl Hydrogen chloride
kWh Kilowatt hours
ISO International Standards Organization
lb Pounds
LFG Landfill gas
MACT Maximum achievable control technology
MATS Mercury Air Toxics Standards
MSU Michigan State University
MMBtu Million British thermal units
NESHAP National Emission Standards for Hazardous Air Pollutants
NPRA National Petrochemical and Refiners Association
NTTAA National Technology Transfer and Advancement Act
NAICS North American Industry Classification System
NO_X Nitrogen oxide
NSR New Source Review
OMB Office of Management and Budget
PM Particulate matter
PSU Penn State University
PS Performance Specification
ppm Parts per million
QA Quality assurance
QC Quality control
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RPU Rochester Public Utilities
RTC Response to comment
SCR Selective catalytic reduction
SNCR Selective non-catalytic reduction
SO_2 Sulfur dioxide
TBtu/yr Trillion British thermal units per year
THC Total hydrocarbon
TSM Total selected metals
TTN Technology Transfer Network
tpy Tons per year
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
USCHPA US Clean Heat Power Association
US Sugar United States Sugar Corporation
UPL Upper prediction limit
UARG Utility Air Regulatory Group
VCS Voluntary Consensus Standards
VOC Volatile organic compounds
WM Waste Management Inc.
WEPCO Wisconsin Electric Power Company
WWW Worldwide Web

Organization of this Document. The information presented in this preamble is organized as follows:

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I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by this action include:

TABLE 2—POTENTIAL REGULATED CATEGORIES AND ENTITIES AFFECTED

Category	NAICS code[1]	Examples of potentially regulated entities
Any industry using a boiler or process heater as defined in the final rule	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries, and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this reconsideration action. To determine whether your facility may be affected by this reconsideration action, you should examine the applicability criteria in 40 CFR 63.7485 of subpart DDDDD (National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters). If you have any questions regarding the applicability of this final rule to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative, as listed in 40 CFR 63.13 of subpart A (General Provisions).

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

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

C. Judicial Review

Under the CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 1, 2013. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

II. Background Information

A. Chronological History of Related Actions

On March 21, 2011, the EPA issued final standards for new and existing industrial, commercial, and institutional boilers and process heaters, pursuant to its authority under section 112 of the CAA. On the same day as the final rule was issued, the EPA stated in a separate notice that it planned to initiate a reconsideration of several provisions of the final rule. This reconsideration notice identified several provisions of the March 2011 final rule where additional public comment was appropriate. This notice also identified several issues of central relevance to the rulemaking where reconsideration was appropriate under CAA section 307(d).

On May 18, 2011, the EPA issued a notice to postpone the effective date of the March 21, 2011 final rule. Following promulgation of the final rule, the EPA received petitions for reconsideration from the following organizations

("Petitioners"): AIE, USCHPA, Alyeska Pipeline, ACC, AHFA, AISI, ACCCI, AMP, API, NPRA, AIF, Citizens Energy Group (CEG), CIBO, CMI, District Energy St. Paul, FSI, GPSP, Hovensa L.L.C., Tesoro Hawaii Corp., Industry Coalition (AF&PA *et al.*), JELD–WEN Inc., MSU, PSU, Purdue University, Renovar Energy Corp., RPU, Sierra Club, Southeastern Lumber Manufacturers Association, State of Washington Department of Ecology, BCSE, UARG, US Sugar, WM and WEPCO. Copies of these petitions are provided in the docket (see Docket ID No. EPA–HQ–OAR–2002–0058). Petitioners, pursuant to CAA section 307(d)(7)(B), requested that the EPA reconsider numerous provisions in the rule. On December 23, 2011, the EPA granted the petitions for reconsideration on certain issues, and proposed certain revisions to the final rule in response to the reconsideration petitions and to address the issues that the EPA previously identified as warranting reconsideration. That proposal solicited comment on several specific aspects of the rule, including:

- Revising the proposed subcategories.
- Solicitation of new data or corrections to existing data to revise emission standards calculations.
- Establishing an alternative TSM limit.
- Appropriateness of an alternative TSM limit for the liquid subcategories.
- Establishing work practice standards for dioxin/furan emissions.
- Revising the efficiency assumptions for the alternative output-based emission standards.
- Accommodating emissions averaging provisions in the alternative output-based emission standards.
- Establishing a mercury fuel specification through which gas-fired boilers that use a fuel other than natural gas or refinery gas may be considered Gas 1 units.
- Establishing a work practice standard for limited use units.
- Providing an affirmative defense for malfunction events.
- Revisions to the monitoring requirements for oxygen in the March 2011 final rule.
- Establishing a full-load stack test requirement for carbon monoxide coupled with continuous oxygen (oxygen trim) monitoring.
- Revising PM monitoring requirements from CEMS to CPMS and exempting biomass units from PM CPMS requirements.
- Revising mercury monitoring requirements to allow for an alternative mercury CEMS.
- Considering use of SO_2 CEMS to demonstrate compliance with HCl limits.
- Minimum data availability provisions.
- Averaging times for monitored parameters and pollutants.
- Revised methods for computing minimum detection levels.
- Providing an alternative CO emission limit based on CO CEMS data.
- Soliciting additional data to set MACT floor emission limits for non-continental liquid units.
- Selecting a 99 percent confidence interval for setting the CO emission limit.
- Tune-up frequencies, timing of initial tune-ups and adjusted tune-up requirements for shutdown units.
- Scope and duration of the energy assessment and deadline for completing the assessment.
- Revising work practices during startup and shutdown.
- Revisions to certain exemptions, including units serving as control devices, waste heat process heaters, units firing comparable fuels and residential units.
- Revisions to reduced testing frequency for emission limits that are established at minimum detection levels.
- Removing fuel analysis requirements for gas 1 fuels at co-fired units.
- Revisions to automating techniques for coal sampling.
- Revisions to emissions averaging across subcategories when units opt to switch to natural gas.
- Consideration of a new subcategory for units installed and used in place of flares.

In this action, the EPA is finalizing multiple changes to the March 2011 final rule after considering public comments on the items under reconsideration.

III. Summary of This Final Rule

As stated above, the December 23, 2011 proposed rule addressed specific issues and provisions the EPA identified for reconsideration. This summary of the final rule reflects the changes to 40 CFR part 63, subpart DDDDD (March 21, 2011 final rule) in regards to those provisions identified for reconsideration and on other discrete matters identified in response to comments or data received during the comment period. Information on other provisions and issues not proposed for reconsideration is contained in the notice and record for the 2011 final rule. [See 76 FR 15608]

This section summarizes the requirements of this action. Section IV below provides a summary of the significant changes to the March 21, 2011 final rule.

A. What is an affected source?

This final rule revises the list of exemptions in § 63.7491 to include residential boilers that may be located at an industrial, commercial or institutional major source. The exemption for boilers or process heaters used specifically for research and development has been revised to include boilers used for certain testing purposes.

B. What are the subcategories of boilers and process heaters?

In this final rule, we are finalizing separate subcategories for heavy liquid-fired, light liquid-fired and liquid-fired units in non-continental locations for PM and CO, pollutants that are dependent on combustor design. In addition, a new subcategory for coal-fired fluidized bed boilers with integrated fluidized bed heat exchangers has been included in the final rule for CO which is dependent on boiler design. Finally, we are finalizing the subcategory for PM at coal/fossil solid units across all coal combustor designs.

C. What emission limits and work practice standards are being finalized?

You must meet the emission limits presented in Table 3 of this preamble for each subcategory of units listed in the table. This final rule includes 19 subcategories, which are based on unit design. New and existing units in three of the subcategories are subject to work practices standards in lieu of emission limits for all pollutants. Numeric emission limits are finalized for new and existing sources in each of the other 16 subcategories.

The changes associated with the emission limits are due to new data, corrections to old data, and inventory changes. In summary, for existing subcategories, for the HCl emission limits, 10 are more stringent, 3 are less stringent and 1 remained the same from the March 21, 2011 final rule; for the mercury emission limits, 3 are more stringent and 11 are less stringent from the March 21, 2011 final rule; for the PM emission limits, 2 are more stringent, 7 are less stringent and 5 are unchanged from the March 21, 2011 final rule; and for the CO emission limits, 4 are more stringent and 10 are less stringent from the March 21, 2011 final rule. For new subcategories, for the HCl emission limits, 13 are less stringent and 1 is unchanged from the March 21, 2011 final rule; for the mercury emission limits, 11 are more

stringent, 2 are less stringent and 1 is unchanged from the March 21, 2011 final rule; for the PM emission limits, 9 are less stringent and 5 are unchanged from the March 21, 2011 final rule; and for the CO emission limits, 3 are more stringent and 11 are less stringent from the March 21, 2011 final rule.

TABLE 3—EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS

[lb/MMBtu heat input basis unless noted; alternative output based limits are not shown in the summary table below]

Subcategory	Filterable PM (or total selected metals) (lb per MMBtu of heat input) [a]	HCl (lb per MMBtu of heat input) [a]	Mercury (lb per MMBtu of heat input) [a]	CO (ppm @3% oxygen) [a]	Alternate CO CEMS limit, (ppm @3% oxygen) [b]
Existing—Coal Stoker	0.040 (5.3E–05)	0.022	5.7E–06	160	340
Existing—Coal Fluidized Bed	0.040 (5.3E–05)	0.022	5.7E–06	130	230
Existing—Coal Fluidized Bed with FB heat exchanger	0.040 (5.3E–05)	0.022	5.7E–06	140	150
Existing—Coal-Burning Pulverized Coal	0.040 (5.3E–05)	0.022	5.7E–06	130	320
Existing—Biomass Wet Stoker/Sloped Grate/Other	0.037 (2.4E–04)	0.022	5.7E–06	1,500	720
Existing—Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.32 (4.0E–03)	0.022	5.7E–06	460	ND
Existing—Biomass Fluidized Bed	0.11 (1.2E–03)	0.022	5.7E–06	470	310
Existing—Biomass Suspension Burner	0.051 (6.5E–03)	0.022	5.7E–06	2,400	[c] 2,000
Existing—Biomass Dutch Ovens/Pile Burners	0.28 (2.0E–03)	0.022	5.7E–06	770	[c] 520
Existing—Biomass Fuel Cells	0.020 (5.8E–03)	0.022	5.7E–06	1,100	ND
Existing—Biomass Hybrid Suspension Grate	0.44(4.5E–04)	0.022	5.7E–06	2,800	900
Existing—Heavy Liquid	0.062 (2.0E–04)	0.0011	2.0E–06	130	ND
Existing—Light Liquid	0.0079 (6.2E–05)	0.0011	2.0E–06	130	ND
Existing—non-Continental Liquid	0.27 (8.6E–04)	0.0011	2.0E–06	130	ND
Existing—Gas 2 (Other Process Gases)	0.0067 (2.1E–04)	0.0017	7.9E–06	130	ND
New—Coal Stoker	0.0011 (2.3E–05)	0.022	8.0E–07	130	340
New—Coal Fluidized Bed	0.0011 (2.3E–05)	0.022	8.0E–07	130	230
New—Coal Fluidized Bed with FB Heat Exchanger	0.0011 (2.3E–05)	0.022	8.0E–07	140	150
New—Coal-Burning Pulverized Coal	0.0011 (2.3E–05)	0.022	8.0E–07	130	320
New—Biomass Wet Stoker/Sloped Grate/Other	0.030 (2.6E–05)	0.022	8.0E–07	620	390
New—Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.030 (4.0E–03)	0.022	8.0E–07	460	ND
New—Biomass Fluidized Bed	0.0098 (8.3E–05)	0.022	8.0E–07	230	310
New—Biomass Suspension Burner	0.030 (6.5E–03)	0.022	8.0E–07	2,400	[c] 2,000
New—Biomass Dutch Ovens/Pile Burners	0.0032 (3.9E–05)	0.022	8.0E–07	330	[c] 520
New—Biomass Fuel Cells	0.020 (2.9E–05)	0.022	8.0E–07	910	ND
New—Biomass Hybrid Suspension Grate	0.026 (4.4E–04)	0.022	8.0E–07	1,100	900
New—Heavy Liquid	0.013 (7.5E–05)	4.4E–04	4.8E–07	130	ND
New—Light Liquid	0.0011 (2.9E–05)	4.4E–04	4.8E–07	130	ND
New—Non-Continental Liquid	0.023 (8.6E–04)	4.4E–04	4.8E–07	130	ND
New—Gas 2 (Other Process Gases)	0.0067 (2.1E–04)	0.0017	7.9E–06	130	ND

NA-Not applicable; ND-No data available
[a] 3-run average, unless otherwise noted.
[b] 30-day rolling average, unless otherwise noted.
[c] 10-day rolling average.

We also are finalizing a work practice standard for dioxin/furan emissions from all subcategories.

D. What are the requirements during periods of startup and shutdown?

We are finalizing revised work practice standards for periods of startup and shutdown to better reflect the maximum achievable control technology during those periods. In addition, we are finalizing definitions of startup and shutdown. We are defining startup as the period between the state of first-firing of fuel in the unit after a shutdown to the period where the unit first supplies steam. We are defining shutdown as the period that begins when no more steam is supplied or at the point of no fuel being fired in the unit. For periods of startup and shutdown, we are finalizing the following work practice standard: You must operate all continuous monitoring systems during startup and shutdown. For startup, you must use one or a combination of the listed clean fuels. Once you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must engage all of the applicable control devices except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR. You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR systems as expeditiously as possible. During shutdown while firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR. You must comply with all applicable emissions and operating limits at all times the unit is in operation except for periods that meet the definitions of startup and shutdown in this subpart, during which times you must comply with these work practices. You must keep records during periods of startup or shutdown. You must keep records concerning the date, duration, and fuel usage during startup and shutdown.

E. What are the testing and initial compliance requirements?

We are requiring that the owner or operator of a new or existing boiler or process heater conduct performance tests to demonstrate compliance with all applicable emission limits. This final rule adds the requirement to conduct initial and annual stack tests to determine compliance with the TSM emission limits using EPA Method 29 for those subcategories with alternate TSM limits.

F. What are the continuous compliance requirements?

This final rule removes the requirement for units combusting biomass with heat input capacities of 250 MMBtu/hr or greater to install, certify, maintain and operate a CEMS measuring PM emissions. This final rule requires units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 MMBtu/hr or greater to install, certify, maintain, and operate PM CPMS. Moreover, owners or operators of units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 MMBtu/hr or greater are allowed to install, certify, maintain and operate PM CEMS as an alternative to the use of PM CPMS, consistent with regulations for similarly-sized commercial and industrial solid waste incinerators units and EGUs subject to the MATS. Just as units using PM CPMS will not be required to conduct parameter monitoring for PM, units using PM CEMS will not be required to conduct parameter monitoring for PM.

This final rule also includes an alternative method of demonstrating continuous compliance with the HCl emission limit. This method allows using SO_2 emissions as an alternate operating limit. This method of demonstrating continuous compliance will be allowed only on a unit that utilizes a SO_2 CEMS and an acid-gas control technology including wet scrubber, dry scrubbers and duct sorbent injection. Boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS would be required to maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

G. What are the compliance dates?

For existing sources, the EPA is establishing a compliance date of January 31, 2016. New sources must comply by January 31, 2013, or upon startup, whichever is later. New sources are defined as sources which commenced construction or reconstruction on or after June 4, 2010 pursuant to section 112(a)(4).

Commenters have argued that the 3-year compliance deadline the EPA is establishing for existing sources to meet the standards does not provide them with sufficient time to meet the standards in view of the large number of sources that will be competing for the needed resources and materials from engineering consultants, permitting authorities, equipment vendors, construction contractors, financial institutions, and other critical suppliers.

As an initial matter, we note that many sources subject to the emission standards in the final rule should be able to meet the standards within three years, even those that need to install pollution control technologies to do so. In addition, many sources subject to the rule are gas fired units or small boilers (less than 10 MMBtu/hr) and will not need to install controls in order to demonstrate compliance, as these sources are subject to work practice standards. For these sources, the 3-year compliance deadline is highly unlikely to be problematic either in general, or with respect to the claims commenters have made about the possibility that the demand for resources related to control technology will exceed the supply.

At the same time, the CAA allows title V permitting authorities to grant sources, on a case-by-case basis, extensions to the compliance time of up to one year if such time is needed for the installation of controls. *See* CAA section 112(i)(4)(i)(A). Permitting authorities are already familiar with, and in many cases have experience with, applying the 1-year extension authority under section 112(i)(4)(A) since the provision applies to all NESHAP. We believe that should the range of circumstances that commenters have cited as impeding sources' ability to install controls within three years materialize, then it is reasonable for permitting authorities to take those circumstances into consideration when evaluating a source's request for a 1-year extension, and where such applications prove to be well-founded, it is also reasonable for permitting authorities to make the 1-year extension available to applicants.

In making a determination as to whether an extension is appropriate, we believe it is also reasonable for permitting authorities to consider the large number of pollution control retrofit projects being undertaken for purposes of complying either with the standards in this rule or with those of other rules such as MATS for the power sector that may be competing for similar resources.

Further, commenters have pointed out that in some cases operators of existing sources that are subject to these standards and that generate energy may opt to meet the standards by terminating operations at these sources and building new sources to replace the energy generation at the shut-down sources. While the ultimate discretion to provide a 1-year extension lies with the permitting authority, the EPA believes that it is reasonable for permitting authorities to allow the fourth year extension for the installation of replacement sources of energy generation at the site of a facility applying for an extension for that purpose. Specifically, the EPA believes where an applicant demonstrates that it is building replacement sources of energy generation for purposes of meeting the requirements of these standards such a replacement project could be deemed to constitute the "installation of controls" under section 112(i)(3)(B).

In a case where pollution controls are being installed or onsite replacement energy generation is being constructed to allow for retirement of older, under-controlled energy generation units, a determination that an extra year is necessary for compliance should be relatively straightforward. In order to install controls, companies are likely to undertake a number of steps relatively soon after the effective date of the rule, including obtaining necessary building and environmental permits and hiring contractors to perform the construction of the emission controls or replacement energy generation units. This should provide sufficient information for a permitting authority to determine that emission controls are being installed or that replacement energy generation is being constructed. As a result, a permitting authority will be in a position to make a determination as to whether a source's compliance schedule will exceed 3 years and to quickly make a determination as to when an extension is appropriate.

In sum, the EPA believes that although most, if not all, units will be able to fully comply with the standards 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. Of course in situations where EPA is the permitting authority, we would also consider the above circumstances when acting on a permit application.

IV. Summary of Significant Changes Since Proposal

The EPA has made numerous changes in this final rule from the proposal after consideration of the public comments received. Most are changes to clarify applicability and implementation issues raised by the commenters. The public comments received on the proposed changes and the responses to them can be viewed in the memorandum "Response to Comments for Industrial, Commercial, and Institutional Boilers

and Process Heaters National Emission Standards for Hazardous Air Pollutants'' located in the docket.

A. Applicability

Since proposal, the EPA has made certain changes to the applicability of this final rule. We have clarified that the exemption for boilers and process heaters used for research and development includes boilers used for testing the propulsion systems on military vessels. This is consistent with the intent of the exemption in that these test boilers do not provide steam for heating, to a process, or other non-propulsion related uses but are used exclusively to test the propulsion systems of nuclear-powered aircraft carriers that are undergoing repair, overhaul, or installation.

B. Subcategories

As described in the preamble to the proposed reconsideration rule, within the basic unit types of boilers and process heaters there are different designs and combustion systems that, while having a minor effect on fuel-dependent HAP emissions, have a much larger effect on pollutants whose emissions depend on the combustion conditions in a boiler or process heater. In the case of boilers and process heaters, the combustion-related pollutants are the organic HAP. In the proposed rule, we identified the following 17 subcategories for organic HAP: (1) Pulverized coal units; (2) stokers designed to burn coal; (3) fluidized bed units designed to burn coal; (4) stokers designed to burn wet biomass; (5) stokers designed to burn kiln-dried biomass; (6) fluidized bed units designed to burn biomass; (7) suspension burners designed to burn biomass; (8) dutch ovens/pile burners designed to burn biomass; (9) fuel cells designed to burn biomass; (10) hybrid suspension grate units designed to burn biomass; (11) units designed to burn heavy liquid fuel; (12) units designed to burn light liquid fuel; (13) non-continental liquid units; (14) units designed to burn natural gas/refinery gas; (15) units designed to burn other gases; (16) metal process furnaces; and (17) limited-use units.

In this final rule, we are also adding a separate subcategory for fluidized bed units with a fluidized bed heat exchanger designed to burn coal and adjusted the definition of the limited use subcategory.

Fluidized bed boilers are designed to combust fuel with relatively low heating value and high ash compared to other combustor designs. Two fuel properties of coal are heating values and ash content. As the heating value of the coal decreases, ash content increases. Fluidized bed boilers are designed to have large tube surface areas to transfer heat from the fuel through the process of conduction and convection, but in some cases the amount of tube surface area in the furnace for heat transfer is insufficient. In order to overcome insufficient heat exchange, certain fluidized bed boilers adopt a fluidized bed heat exchanger design to achieve heat transfer. The fluidized bed heat exchanger is located at the exit of the cyclone section of the unit. This design allows the boiler to combust coal with a lower heating value than a coal-fired fluidized bed boiler without a fluidized bed heat exchanger. Therefore, because this boiler design does have different combustion-related HAP emission characteristics, a new subcategory of coal fluidized bed with integrated heat exchanger was added to the final rule.

The EPA is also revising the definition of the limited use subcategory. Many affected units operate on standby mode or low loads for periods longer than the proposed definition for limited use units, which limited operation to 876 hours per year. By converting to a capacity-factor approach, we are allowing more flexibility on unit operations without increasing emissions or harm to human health and the environment. For example, units operating at 10 percent load for 8,760 hours per year would emit the same amount of emissions as units operating at full load for 876 hours per year. Further, it is technically infeasible to schedule stack testing for these limited use units since these units serve as back up energy sources and their operating schedules can be intermittent and unpredictable. The limited use subcategory was adjusted to be based on units with a federally enforceable operating limit of less than or equal to 10 percent of an average annual capacity factor.

C. Performance Test Requirements

Table 5 of this final rule has been revised to add performance test procedures for conducting performance stack tests for demonstrating compliance with the alternate TSM emission limits. In the reconsideration proposal, we proposed emissions limits for TSM (i.e., arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium) as an alternative to the proposed PM emission limits for many of the subcategories. In the preamble to the proposed rule, we added procedures in Table 6 of the rule for conducting fuel analysis for total selected metals but we inadvertently failed to add performance test requirements for stack sampling of TSM emissions in Table 5 of the rule.

D. Emission Limits

One significant change since proposal is related to the PM emission limits for the coal subcategories. Several petitioners disagreed with EPA's position to set different PM limits for subcategories of boilers and process heaters based on the fuel used, and instead offered information to support the position that PM should be considered a combustion-based pollutant. The differences in PM particle size, fouling characteristics and feasibility of certain control technologies on certain unit designs suggested that PM is more appropriately classified as a combustion-based pollutant, but only for the coal subcategories. After assessing the points raised by the petitioners, the EPA agreed that PM emissions are influenced by unit design, and fuel type, and proposed to create combustion-based pollutant subcategories for coal and solid fuels and create fuel-based subcategories for liquid and biomass fuel units. The EPA is finalizing a single PM limit for all coal/solid fossil fuel subcategories, and is also finalizing emissions limits based on PM as a combustion-based pollutant for the biomass and liquid fuel subcategories.

Another change from proposal is that the alternative TSM emission limits are now applicable to the three liquid fuel subcategories. Several commenters provided data and comments supporting these alternative emission standards for non-mercury metallic HAP. After assessing the revised data and the points made by the commenters, the EPA agrees that the limited data available for liquid fuel units are not unique to this subcategory. Based on the EPA agreeing with the commenters, the EPA re-calculated the TSM emission limits for the liquid fuel subcategories and included them in the final rule.

The CO emission limit for several subcategories, both new and existing, have been revised to reflect a CO level that is consistent with MACT for organic HAP reduction. Several commenters recommended that the EPA evaluate a minimum CO standard (i.e., 100 ppm corrected to 7 percent oxygen) to serve as a lower bound surrogate for organic HAP. Commenters also provided data and information to support such a standard, and noted that the EPA has taken a similar approach in other emission standards under section 112.

The EPA evaluated whether there is a minimum CO level for boilers and

process heaters below which there is no further benefit in organic HAP reduction/destruction. Specifically, we evaluated the relationship between CO and formaldehyde using the available data obtained during the rulemaking. Formaldehyde was selected as the basis of the organic HAP comparison because it is the most prevalent organic HAP in the emission database and a large number of paired tests existed for boilers and process heaters for CO and formaldehyde. The paired data show decreasing formaldehyde emissions with decreasing CO emissions down to CO levels around 300 ppm, supporting the selection of CO as a surrogate for organic HAP emissions. A slight increase in formaldehyde emissions is observed at CO levels below around 200 ppm, suggesting a breakdown in the CO-formaldehyde relationship at low CO levels. At levels lower than 150 ppm, the mean levels of formaldehyde appear to increase, as does the overall maximum value of and variability in formaldehyde emissions. However, we are aware of no reason why CO concentrations would continue to decrease and formaldehyde concentrations would increase as combustion conditions improve. It is possible that imprecise formaldehyde measurements at low concentrations (i.e., 1–2 ppm) may account for this slight increase in formaldehyde emissions observed at CO levels below 100 ppm corrected to 7 percent oxygen. Based on this, we do not believe that such measurements are sufficiently reliable to use as a basis for establishing an emissions limit.

Therefore, based on the above analysis, we are promulgating a minimum MACT floor level for CO of 130 ppm corrected to 3 percent oxygen (which is equivalent to 100 ppm corrected to 7 percent oxygen). We note this is the same approach used to establish the CO emission limit of 100 ppm corrected to 7 percent oxygen for the Burning of Hazardous Waste in Boilers and Industrial Furnaces rule. Additional discussion of the rationale for this approach can be found in the memorandum "Revised MACT Floor Analysis (August 2012) for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source."

Subcategories where the initial MACT floor 99 percent UPL calculations for CO were less than 100 ppm corrected to 7 percent oxygen (or equivalently 130 ppm corrected to 3 percent oxygen) are as follows:

- New and Existing Subcategories: Coal-FB, Coal-PC, Heavy Liquid, Light Liquid, Non-Continental Liquid, Process Gas
- New Subcategories: Coal-Stoker

We believe a CO level of 130 ppm corrected to 3 percent oxygen is an appropriate minimum MACT floor level. Although some measurements show CO levels below 130 ppm corrected to 3 percent oxygen, it is not appropriate to establish a lower floor level because CO is a conservative surrogate for organic HAP. In other words, organic HAP emissions are extremely low when sources operate under the good combustion conditions required to achieve CO levels in the range of zero to 100 ppm. As such, lowering the CO floor below 100 ppm will not provide reductions in organic HAP emissions. There are myriad factors that affect combustion efficiency and, as a function of combustion efficiency, CO emissions. As combustion conditions improve and hydrocarbon levels decrease, the larger and easier to combust compounds are oxidized to form smaller compounds that are, in turn, oxidized to form CO and water. As combustion continues, CO is then oxidized to form carbon dioxide and water. Because CO is a difficult to destroy refractory compound (*i.e.,* oxidation of CO to carbon dioxide is the slowest and last step in the oxidation of hydrocarbons), it is a conservative surrogate for destruction of hydrocarbons, including organic HAP.

The conservative nature of CO as an indicator of good combustion practices is supported by our data. At CO levels less than 100 ppm corrected to 7 percent oxygen, our data indicate that there is no apparent relationship between CO and organic HAP (i.e., formaldehyde). For example, a source with a CO level of 20 ppm may have the same measured formaldehyde as a source achieving a CO emission level of 100 ppm corrected to 7 percent oxygen. Sources are required to establish operating requirements based on operating levels that were demonstrated during the test. Sources must comply with these operating requirements on a continuous basis. Compliance with these requirements adequately assures sources will be controlling organic HAP emissions to MACT levels.

As detailed in the docketed memorandum "Beyond the Floor Technology Analysis for Major Source Boilers and Process Heaters (Revised August 2012)," we reviewed the emission limits that are becoming less stringent since the March 2011 final rule in order to assess whether a beyond the floor option was technically achievable and cost effective. As a result of this review, the PM emission limits for several new biomass subcategories have been changed to reflect a beyond the floor limit of 0.03 lb/MMBtu, based on the limit for new biomass boilers in 40 CFR part 60 subparts Db and Dc. Due to the low mercury emission limits for new solid fuel boilers, these new biomass units are expected to install a fabric filter level of control in order to meet the new source mercury limits for the solid fuel subcategory. This mercury control has the co-benefit of reducing PM emissions down to levels of 0.03 lb/MMBtu so there is no incremental cost to achieve these additional reductions in PM for the biomass units that have a design heat input capacity between 10 and 30 MMBtu/hr. For units with a design heat input capacity of 30 MMBtu/hr or greater, these units are already subject to a PM limit of 0.03 lb/MMBtu and adjusting these new source limits to this level of control makes the limits consistent between both rules, without adding additional costs. We did not identify any beyond the floor options for existing source PM limits or new and existing limits for other pollutants as technically feasible or cost effective.

The other changes associated with the other emission limits are due to new data, corrections to old data, and inventory changes. In summary, compared to the December 23, 2011 proposed limits for existing units, the final HCl emission limits remained the same; for the final mercury emission limits, 3 are more stringent, 10 are less stringent and 1 is unchanged; for the final PM emission limits, 3 are more stringent, 5 are less stringent and 6 are unchanged; and for the final CO emission limits, 3 are more stringent and 11 are less stringent. For new units, compared to the proposed emission limits, 3 of the final HCl emission limits are more stringent and 11 remained the same; for the final mercury emission limits, 10 are more stringent and 4 are unchanged; for the final PM emission limits, 5 are more stringent, 2 are less stringent and 7 are unchanged; and for the final CO emission limits, 2 are more stringent, 11 are less stringent and 1 is unchanged.

E. Work Practice Requirement

In this final rule several changes have been made to the work practice requirement to conduct a tune-up. First, the requirement to inspect the burner has been revised to allow units that sell electricity to schedule the burner inspection, as well as the air-to-fuel system inspection, at the time of the first outage but not to exceed 36 months from the previous inspection. This

change is being made to this final rule because commenters stated that large boilers that serve electricity for sale may not require annual outages and would, therefore, need to be taken off-line for the sole purpose of an annual tune-up. This frequency is consistent with the requirements of the NESHAP for electric utility boilers (40 CFR part 63, subpart UUUUU).

Also, for units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or into process equipment. Commenters indicated that some process heaters are installed inside tanks and entry into the tank to access the heater may not occur within a 5 year period.

The requirement to optimize total emissions of CO has been revised to require that this optimization not only be consistent with the manufacturer's specifications but also with any NO_X emission requirement to which the unit is subject. Some commenters indicated that many boilers need different tune-up criteria due to their requirement to also comply with low NO_X emission limits. We are also aware that several states have boiler tune-up requirements to minimize NO_X emissions first and then optimize CO emissions.

We have added boilers or process heaters that have a continuous oxygen trim system to the types of boilers or process heaters that must conduct a tune-up every 5 years. These units do not need to be tuned as frequently because the trim system is designed to continuously measure and maintain an optimum air to fuel ratio which is the purpose of a tune-up.

F. Averaging Times Definitions

We revised the definitions of ''30-day rolling average'' and ''daily block average'' to exclude periods of startup and shutdown or downtime from the arithmetic mean. Commenters requested that the EPA specify how a 30-day rolling average is calculated and whether it includes the previous 720 hours of valid operating data and that the valid data exclude hours during startup and shutdown as well as unit down time. We agree with the commenters that the definitions need clarification and that these periods should not be included in calculating the 30-day rolling average. Therefore, we have revised the definitions accordingly.

We have also included in the final rule a definition of ''10-day rolling average'' that is consistent with the revised definition of ''30-day rolling average.''

G. Energy Assessment

In this final rule, we have revised the definition of energy assessment per the requirements of Table 3 of this final rule by providing duration for performing the energy assessment for large fuel use facilities. In numbered paragraph (3) in the definition of ''Energy assessment'' in § 63.7575, which is for facilities with units having a combined heat input capacity greater than 1 TBtu/yr, we added time duration/size ratio and included a cap to the maximum number of on-site technical hours that should be used in the energy assessment. This addition of a duration for large fuel use facilities is being made to be consistent with durations specified for small [paragraph (1) in the definition of ''Energy assessment''] and medium [paragraph (2) in the definition of ''Energy assessment''] fuel use facilities. The energy assessment for facilities with affected boilers and process heaters having a combined heat input capacity greater than 1.0 TBtu/yr will be up to 24 on-site technical labor hours for the first TBtu/yr plus 8 technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 technical hours, but may be longer at the discretion of the owner or operator.

The revised definition of energy assessment also clarifies our intentions that the scope of assessment is based on energy use by discrete segments of a facility and not by a total aggregation of all individual energy using elements of a facility. The applicable discrete segments of a facility could vary significantly depending on the site and its complexity. We have added the following paragraph (4), to the energy assessment definition to help resolve current problems in identifying the scope of the various energy use systems in a large industrial complex and allow for more streamlined assessments:

''(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy output in (1), (2) and (3) above may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).''

We have also revised paragraph 4 of Table 3 of the final rule to allow a source that is operating under an energy management program established through energy management systems compatible with ISO 50001, which includes the affected units, to satisfy the energy assessment requirement. We consider these energy management programs to be equivalent to the one-time energy assessment because facilities having these programs operate under a set of practices and procedures designed to manage energy use on an ongoing basis. These programs contain energy performance measurements and tracking plans with periodic reviews.

The definition of ''Energy use system'' has also been revised in this final rule to clarify that energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

H. Startup and Shutdown Definitions

A number of commenters indicated that the proposed load specifications (i.e., 25 percent load) within the definitions of ''startup'' and ''shutdown'' were inconsistent with either safe or normal (proper) operation of the various types of boilers and process heaters encountered within the source category. As the basis for defining periods of startup and shutdown, a number of commenters suggested alternative load specifications based on the specific considerations of their boilers; other commenters suggested the achievement of various steady-state conditions.

We have reviewed these comments and believe adjustments are appropriate in the definition of ''startup'' and ''shutdown.'' These adjustments are tailored for industrial boilers 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 industrial boilers function to provide steam or, in the case of cogeneration units, electricity; therefore, industrial boilers should be considered to be operating normally at all times steam of the proper pressure, temperature, and flow rate is being supplied to a common header system or energy user(s) for use as either process steam or for the cogeneration of electricity. The definitions of ''startup'' and ''shutdown'' have been revised in the final rule as follows:

''*Startup* means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler or process heater after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose.''

"*Shutdown* means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam and heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is both no steam or heat being supplied and no fuel being fired in the boiler or process heater."

The EPA 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 limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR) when firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel or gas 2 (other) gases in the boiler or process heater during startup or shutdown. It is the responsibility of the operators of affected boilers and process heaters to start their limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR systems appropriately to comply with relevant standards applicable during normal operation. Startup ends and normal operating standards apply when heat or steam is supplied for any purpose.

The EPA carefully considered fuels and potential operational constraints of APCD when designing its work practices for periods of startup and shutdown. The EPA notes that there is no technical barrier to burning clean fuels (e.g., natural gas, distillate oil) for longer portions of startup or shutdown periods 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 APCD. The EPA is aware that SNCR and 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, and that fabric filters need to be operated at temperatures above the acid dew point. 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 affected boilers and process heaters to start their SNCR, SCR, fabric filter and dry scrubber systems appropriately to comply with relevant standards applicable during normal operation.

I. Fuel Sampling Frequency

The sampling frequency for gaseous fuel-fired units that elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory has been revised in this final rule. If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification, no further sampling is required. If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification, only semi-annual sampling need to be conducted. If the initial mercury constituents are greater than 75 percent of the mercury specification, monthly sampling is required.

J. Affirmative Defense

In the proposal, we used terms such as "exceedance" or "excess emissions" in § 63.7501, which created unnecessary confusion as to when the affirmative defense could be used. In the final amended rule, we have eliminated those terms and used the word "violation" to make clear that the affirmative defense to civil penalties is available only where an event that causes a violation of the emissions standard meets the definition of malfunction under § 63.2.

We have also eliminated the 2-day notification requirement that was included in 40 CFR 63.7501(b) at proposal because we expect to receive sufficient notification of malfunction events that result in violations in other required compliance reports, such as the malfunction report required under 40 CFR 63.7550(c). In addition, we have revised the 45-day affirmative defense reporting requirement that was included in 40 CFR 63.7501(b) at proposal to require sources to include the report in the first compliance, deviation or excess emission report due after the initial occurrence of the violation, unless the compliance, deviation or excess emission report is due less than 45 days after the violation. In that case, the affirmative defense report may be included in the second compliance, deviation or excess emission report due after the initial occurrence of the violation. Because the affirmative defense report is now included in a subsequent compliance, deviation or excess emission report, there is no longer a need for the proposed 30-day extension for submitting a stand-alone affirmative defense report. Consequently, we are not including this provision in the final amended rule. We have also re-evaluated the language concerning the use of off-shift and overtime labor to the extent practicable and believe that the language is not necessary. Thus, we have deleted that phrase from section 63.7501(a)(2).

V. Other Actions We Are Taking

Section 307(d)(7)(B) of the CAA states 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. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time 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, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b))."

As to the first procedural criterion for reconsideration, a petitioner must show why the issue could not have been presented during the comment period, either because it was impracticable to raise the issue during that time or because the grounds for the issue arose after the period for public comment (but within 60 days of publication of the final action). The EPA is denying the petitions for reconsideration on a number of issues because this criterion has not been met. In many cases, the petitions reiterate comments made on the proposed June 2011 rule during the public comment period for that rule. On those issues, the EPA responded to those comments in the final rule and made appropriate revisions to the proposed rule after consideration of public comments received. It is well-established that an agency may refine its proposed approach without providing an additional opportunity for public comment. See *Community Nutrition Institute* v. *Block,* 749 F.2d at 58 and *International Fabricare Institute* v. *EPA,* 972 F.2d 384, 399 (D.C. Cir. 1992) (notice and comment is not intended to result in "interminable back-and-forth[,]" nor is agency required to provide additional opportunity to comment on its response to comments) and *Small Refiner Lead Phase-Down Task Force* v. *EPA,* 705 F.2d 506, 547 (D.C. Cir. 1983) ("notice requirement

should not force an agency endlessly to repropose a rule because of minor changes'')

In the EPA's view, an objection is of central relevance to the outcome of the rule only if it provides substantial support for the argument that the promulgated regulation should be revised. See *Union Oil* v. *EPA,* 821 F.2d 768, 683 (D.C. Cir. 1987) (court declined to remand rule because petitioners failed to show substantial likelihood that final rule would have been changed based on information in petition). See also the EPA's *Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202 of the Clean Air Act,* 75 FR at 49556, 49561 (August 13, 2010). See also, 75 FR at 49556, 49560–49563 (August 13, 2010) and 76 FR at 4780, 4786–4788 (January 26, 2011) for additional discussion of the standard for reconsideration under CAA section 307(d)(7)(B).

We are denying reconsideration on the following 57 issues contained in the petitions for reconsideration because they failed to meet the standard described above for reconsideration under CAA section 307(d)(7)(B). Specifically, on these issues, the petitioner has failed to show the following: that it was impracticable to raise their objections during the comment period or that the grounds for their objections arose after the close of the comment period; and/or that their concern is of central relevance to the outcome of the rule. Therefore, the EPA is denying the petitions for reconsideration on the issues for the reasons described below.

Issue: Delist gas units.

The petitioners (API, NPRA) requested that the EPA remove gas-fired units from the section 112(c) list of source categories for which the EPA is required to establish emissions standards under section 112(d). The EPA is denying the petition for reconsideration for the following reasons. First, the issue is outside the scope of this rulemaking, which establishes emissions standards for new and existing units within the major source boilers and process heaters source category. The EPA did not solicit comment in the proposed rule regarding the scope of the subcategory. Further, petitioners provide no information to support delisting gas units under section 112(c)(9), which requires the EPA to make certain findings before delisting any sources. In addition, the petition does not address the D.C. Circuit's decision in *NRDC* v. *EPA,* 489 F.3d 1364 (2007), regarding the EPA's ability to delist subcategories of a source category pursuant to section 112(c)(9). For these reasons, the petitions do not provide support for the argument that the regulation should be changed. For this reason, the petition does not demonstrate that the issue is of central relevance to the outcome of the final rule and the EPA is denying the request for reconsideration.

Issue: Exempt natural gas hot water heaters with tanks greater than 120 gallons.

The petitioner (AIF) requested that the EPA exempt natural gas hot water heaters with tanks greater than 120 gallons. While the EPA disagrees with the petitioner regarding whether such units should be subject to the emissions standards in this rule, the petitioner has not demonstrated that it lacked the opportunity to comment on whether such units should be required to meet emissions standards. The EPA proposed work practice standards for such units in its June 2010 proposal, and the petitioner had the opportunity to comment on whether such standards should be applied to such units at all. Therefore, the EPA is denying the request for reconsideration.

Issue: Exempt natural gas and distillate oil-fired circulating hot water systems with a design capacity of 10 MMBtu/hr or less.

The petitioner (CIBO) requested that the EPA exempt natural gas and distillate oil-fired circulation hot water systems that are not greater than 10 MMBtu/hr. While the EPA disagrees with the petitioner regarding whether such units should be subject to the emissions standards in this rule, the petitioner has not demonstrated that it lacked the opportunity to comment on whether such units should be required to meet emissions standards. The EPA proposed emissions standards for such units, and the petitioner had the opportunity to comment on whether such standards should be applied to such units at all. In addition, the petition does not provide any information to demonstrate that these units should be delisted pursuant to section 112(c)(9). Therefore, the EPA is denying the request for reconsideration.

Issue: Confirm in definitions that open flame heaters (e.g., asphalt tank heaters) are not process heaters.

The petitioners (API, NPRA) requested that the EPA clarify in the definition of ''process heater'' that open flame heaters do not meet the definition. While the EPA disagrees with the petitioners whether clarification is needed in regards to open flame heaters, the petitioners have not demonstrated that it lacked the opportunity to comment on the proposed definition. The definition that the EPA proposed clearly states that process heaters are enclosed devices in which the combustion gases do not come into contact with process materials, and as such, does not include open flame heaters. Therefore, the EPA is denying reconsideration.

Issue: For blast furnace fuel-fired boiler exemption, compute the 90 percent BFG by volume threshold to exclude periods of BFG curtailment.

The petitioners (AISI, ACCCI) requested that the EPA revise the exemption for BFG fuel-fired boilers to exclude periods of BFG curtailment. While the EPA disagrees with the petitioners regarding revising the exemption, the petitioners have not demonstrated that it lacked the opportunity to comment on the proposed exemption for BFG fuel-fired boilers. The EPA proposed the exemption for these boilers, and petitioners therefore had the opportunity to comment on whether the exemption should apply to periods of BFG curtailment. Therefore, the EPA is denying the request for reconsideration.

Issue: Exempt boilers whose flue gases are used in direct-fired process heaters subject to other NESHAP.

The petitioner (CMI) requested that the EPA exempt from the rule boilers whose flue gases are used in direct-fired process heaters that are subject to other NESHAP. The final rule does not apply to such units if they are subject to another NESHAP. The EPA does not see a need for further clarification. Since the final rule does in fact exempt these units, the EPA is denying the request for reconsideration.

Issue: Work practice standards do not meet EPA obligations under 112(c)(6).

The petitioner (Sierra Club) requested that the EPA establish numeric emissions limits for Gas 1 units rather than work practice standards. Specifically, the petitioner alleges that the work practice standards do not meet the EPA's obligations under section 112(c)(6) of the CAA, and that it was not the case that data were below the detection level for all HAP emitted from these units. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's arguments regarding the legal authority to establish work practice standards for Gas 1 units and the basis for such standards, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed work practice standards for Gas 1 units and explained in the proposal its rationale for such standards, including the fact that a significant portion of the

emissions data were below the detection level. 75 *FR* at 32024–25. Therefore, the petitioner had the opportunity to comment on this issue, and did in fact submit comments regarding the EPA's legal authority to establish work practice standards for Gas 1 units. Therefore, the EPA is denying reconsideration on this issue.

Issue: Work practices for small units are not justified by 112(h) since small units were not given their own subcategory.

The petitioner (Sierra Club) requested that the EPA require small units, those having a heat input capacity of less than 10 MMBtu/hr, to meet numeric emissions limits rather than work practice standards. The EPA is denying the request for reconsideration on this issue because the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed work practice standards for these units and explained in the proposal its rationale for such standards. 75 *FR* at 32024–25. The EPA did in fact receive comments regarding the proposed standards, to which it responded in the final rule. 76 *FR* at 15640. Moreover, the EPA notes that nothing in section 112(h) limits the EPA's discretion to establish work practice standards to the establishment of such standards for an entire category or subcategory. Therefore, the EPA is denying the request for reconsideration.

Issue: PM is not an adequate surrogate for non-mercury metallic HAP.

The petitioner (Sierra Club) requested that the EPA remove the PM standard as a surrogate for non-mercury metallic HAP and instead adopt a numeric limit for non-mercury metallic HAP because PM is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of PM as a surrogate for non-mercury metallic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed PM standards as a surrogate for non-mercury metallic HAP and explained in the proposal the agency's basis for concluding that PM was an appropriate surrogate. 75 *FR* at 32018. Therefore, the EPA is denying the request for reconsideration.

Issue: Establish direct limits on organics or select a surrogate besides CO.

The petitioner (Sierra Club) requested that the EPA remove the CO standard as a surrogate for organic HAP and instead adopt a numeric limit for these HAP, because CO is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of CO as a surrogate for organic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed CO standards as a surrogate for organic HAP and explained in the proposal the agency's basis for concluding that CO was an appropriate surrogate. 75 *FR* at 32018. The EPA received comments on this issue, including comments stating that CO is not an appropriate surrogate for organic HAP. Therefore, the EPA is denying the request for reconsideration.

Issue: Adopt an alternative THC emission standard.

The petitioner (CIBO) requested that the EPA adopt a THC emissions standard as an alternative to the CO standard. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding whether a THC alternative standard is appropriate as a surrogate for non-dioxin organic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA raised in the proposal the possibility of THC as a surrogate for non-dioxin organic HAP, and explained why the use of CO as a surrogate was preferable. 75 *FR* at 32018. In addition, the EPA did not receive any comments or data during the public comment period on the proposed rule that would have enabled the agency to establish a THC alternative standard, including THC emissions data, nor did the petitioner provide any such data. Therefore, the petition does not provide substantial support for its argument that the final rule should be changed. For these reasons, the EPA is denying the petition for reconsideration on this issue.

Issue: Regulation of Total dioxin/furans exceeds statutory authority as only 2 compounds are in 112(b)(1).

The petitioners (AISI, ACCCI, AF&PA) alleged that the EPA lacks statutory authority to regulate total dioxin/furans under CAA section 112, and that the EPA's response in the final rule explaining why it is issuing a total dioxin/furan standard was not a logical outgrowth of the proposed rule. The EPA is denying the request for reconsideration on this issue. First, the EPA disagrees that the final rule is not a logical outgrowth of the proposal. The EPA proposed emissions standards for total dioxin/furans and adopted a final emissions standard for the same pollutant. Therefore, the commenter had the opportunity to provide its views during the public comment period regarding the EPA's proposed emissions standard, including its views regarding the EPA's authority to regulate the pollutant at issue. The fact that the EPA responded to those comments does not mean that the petitioner lacked the opportunity to comment—in fact, the petitioner did provide such comments. 76 *FR* at 15640. For this reason, the EPA is denying the petition for reconsideration.

Issue: HCl is an inadequate surrogate for all acid gases.

The petitioner (Sierra Club) requested that the EPA remove the HCl standard as a surrogate for acid gases and instead adopt a numeric limit for these HAP, because HCl is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of HCl as a surrogate for acid gases, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed HCl standards as a surrogate for acid gases and explained in the proposal the agency's basis for concluding that HCl was an appropriate surrogate. 75 *FR* at 32018. While the EPA had emission data for HCl from hundreds of affected units upon which to establish standards, the EPA did not have sufficient data on the other acid gases to do so (hydrogen fluoride, hydrogen cyanide and chlorine). The petitioner did not refer to any such data and, therefore, the issue is not of central relevance to the outcome of the final rule. Therefore, the EPA is denying the request for reconsideration.

Issue: Establish work practice for other organic HAP instead of using CO as a surrogate.

The petitioners (AMP, JELD–WEN) requested that the EPA adopt a work practice standard for organic HAP rather than a numeric emissions limit based on CO as a surrogate for organic HAP. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees that a work practice standard is appropriate for such HAP for the subcategories for which the EPA adopted a numeric CO limit in the final rule, the petitioners have not demonstrated that they lacked the opportunity to comment on this issue. The EPA proposed numeric CO limits rather than a work practice, and the petitioners had the opportunity to provide their views during the public comment period on the proposed rule regarding why it believed a work practice standard should instead be

finalized. Therefore, the EPA is denying the petition for reconsideration.

Issue: Allow health based compliance alternatives for HCl, other acid gases and manganese.

The petitioners (AMP, AF&PA, AHFA, AISI, ACCCI, RPU, CIBO) requested that the EPA adopt a HBES for HCl and other acid gases as well as for manganese, pursuant to section 112(d)(4). The petitioners also requested that the EPA grant reconsideration on this issue to better address the comments and data submitted during the public comment period for the proposed rule. The EPA is denying the request for reconsideration of this issue. The EPA did not propose a HBES for any pollutants, but did solicit public comment on such standards, explaining its concerns regarding health-based standards, including the lack of available data on which to base such standards. 75 *FR* at 32030. The EPA received comments addressing those concerns and responded to them in the final rule. 76 *FR* at 15642. Therefore, the petitioners have not demonstrated that it lacked the opportunity to comment on this issue. Further, the EPA received no data during the public comment period for the proposed rule on which it could base a HBES for HCl, other acid gases or manganese. Therefore, the petitions do not provide substantial support to demonstrate that the final rule should be changed. For these reasons, the EPA is denying the petition for reconsideration.

Issue: Provide additional compliance alternatives according to Executive Order 13563 (additional subcategories and HBES).

The petitioner (AHFA) requested that the EPA provide additional compliance alternatives in the final rule pursuant to Executive Order 13563 (Improving Regulation and Regulatory Review), including HBES. The EPA is denying the request for reconsideration on this issue because it is not of central relevance. First, nothing in Executive Order 13563 affects the EPA's discretion to establish HBES under the CAA. Additionally, the petition does not provide any information to address our concerns regarding HBES or data to establish such standards.

Issue: Remove energy assessment requirements.

The petitioners (AHFA, AISI, ACCCI, API, NPRA, AIF, CIBO, AF&PA, U.S. Sugar) requested that the EPA remove from the final rule the requirement that existing sources conduct an energy assessment. The EPA is denying the request for reconsideration on this issue. The EPA proposed an energy assessment requirement as a beyond-the-floor standard, and petitioners commented on that proposal. The EPA addressed those comments in the final rule, and petitioners have not demonstrated that they lacked the opportunity to comment on whether the EPA should require an energy assessment, including the EPA's legal authority to do so. 76 *FR* at 15631. Therefore, the EPA is denying the petition for reconsideration. The EPA continues to believe that an energy assessment is not only authorized by the CAA but required as a cost-effective beyond-the-floor standard in accordance with section 112(d)(2).

Issue: Require energy assessment to be conducted every 5 years.

The petitioner (Washington Dept. of Ecology) requested that the EPA require more frequent energy assessments. The EPA proposed a one-time assessment (75 *FR* at p. 32036) and the petitioner has not demonstrated it lacked the opportunity to comment on the frequency of the assessment requirement. Therefore, the EPA is denying the petition.

Issue: Modify cost analysis to include potential fuel savings from implementing assessment findings.

The petitioners (AIE, USCHPA) requested that the EPA modify its cost impacts analysis to include potential fuel savings from implementing energy assessment findings. The EPA is denying the petition. The impacts analysis, including specific mention of how cost savings for energy assessments were handled quantitatively, was explained in the proposal (see 75 FR 32026), and the petitioner therefore had the opportunity to comment on this issue. For this reason, the EPA is denying the petition for reconsideration on this issue.

Issue: Reconsider definition of "cost effective."

The petitioners (AIE, USCHPA) requested that the EPA reconsider the definition of "cost-effective" in the final rule. The EPA is denying the request for reconsideration on this issue. The EPA proposed to define cost-effective energy conservation measures as any measure with return of investment period of two years or less. 75 *FR* at 32036. The petitioners have not demonstrated it lacked the opportunity to comment on the proposed definition. Therefore, the EPA is denying the petition for reconsideration.

Issue: Establish work practice for other organic HAP instead of using CO surrogate.

The petitioners (AMP, JELD–WEN) requested that the EPA establish work practice standards for controlling organic HAP instead of using CO as a surrogate for organic HAP and establishing CO emission limits. The EPA is denying the request for reconsideration on this issue. Use of CO as a surrogate for organic HAP was subject to notice and comment. (75 FR 32018, 75 FR 32041). Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, see section "Choice of Regulated Pollutants: THC vs. CO vs. Other Organic HAP".

Issue: Provide alternative format for units of measure for CO emission limits to allow sources to use their existing monitoring equipment.

The petitioners (UARG, CIBO) requested that the EPA provide an alternative format (ppm at X percent CO_2) for units of measure for CO emissions in addition to ppm at 3 percent oxygen. The EPA is denying the petition because the petitioners do not demonstrate that it was impracticable to comment on this issue. The format for units of measure for the limits was provided in the proposed rule, and petitioners could have commented on whether the proposed units were appropriate.

Issue: New source emission limits are unachievable and the EPA should collect additional fuel variability data from top performing units to adjust the limits.

The petitioner (AF&PA) requested that the EPA adjust the emissions limits for new sources by collecting additional data from the best performing units that they believed would result in increased variability. The petitioners have not demonstrated that they lacked the opportunity to comment. We proposed standards based on the data we had, including data collected during the ICR process in which petitioners participated, and that data were available for public review. Therefore, petitioners could have commented on this issue. Second, the CAA requires that we base the standards on the sources for which we have emissions information. Petitioners are always free to provide more information to us and the EPA specifically requested new data at each stage of the rulemaking to support the development of emission limits for each subcategory. (75 FR 32041, 76 FR 28663, 76 FR 80612). The EPA has incorporated revised data corrections or new data submittals in its analysis for the final rule. The EPA is denying the request for reconsideration.

Issue: Adjust the methodology for computing MACT floors to address statistical errors and variability concerns.

The petitioners (AISI, ACCCI, AF&PA) requested that the EPA adjust the

methodology for computing MACT floors to address statistical errors and variability concerns, including: (1) Dataset reflects the ''best of the best'' units; (2) misapplication of statistical formulae to address distribution, confidence limits, and variability; and (3) failure to address variability in emissions from one unit over time. The methods used to compute the MACT floors were subject to notice and comment. Where new data or data corrections have been submitted that might alter data distributions, identifying best performers or application of fuel variability factors, these changes have been made in the final rule, but the general methodology remains the same. See *Solite Corp.* v. *EPA,* 952 F.2d 473, 485 (D.C. Cir. 1991) (public had sufficient notice of final rule threshold calculations where methodology did not change significantly from proposed rule). The EPA explained the MACT floor methodology in the proposed rule, and addressed comments received on the proposed methodology in the final rule (75 FR 32019–26, 32027–29, 76 15621–30, 76 FR 80614). Therefore, the EPA is denying the request for reconsideration.

Issue: Modify the basis for ranking the top performing units.

The petitioner (WEPCO) requested that the EPA modify the basis for ranking the top performing units, especially for new units, according to the average performance of the unit. The EPA is denying the petition. The methods used to rank units to establish the MACT floors were subject to notice and comment. The EPA explained its methodology in the proposed rule and addressed comments received on the ranking of data for computing the MACT floor in the final rule (75 FR 32019–26, 32027–29, 76 FR 15627).

Issue: Do not use a pollutant-by-pollutant approach to establish MACT floors.

The petitioners (AISI, ACCCI, AF&PA) requested that the EPA not use a pollutant-by-pollutant approach to establish MACT floors. The petitioners stated that this method is not a reasonable interpretation of Section 112(d)(3) of the CAA and that MACT floors should reflect levels achieved in practice, not aspirational controls. The EPA is denying the petition for reconsideration on this issue because it does not demonstrate that it was impracticable to comment on the issue. The EPA proposed MACT floors based on the pollutant-by-pollutant methodology, and therefore petitioners could, and in fact did, provide comments opposing this approach. See 75 FR 32021, 32029. The EPA addressed comments received on this approach in the final rule (76 FR 15621–23). Therefore, the EPA is denying the petition.

Issue: Revise approach to establish MACT floors where there is non-detect data.

The petitioner (Sierra Club) requested that the EPA not use the approach it used in the final rule based on the representative detection level (RDL) to establish MACT floors because it does not reflect actual emissions of any source within the subcategory. Further, the petitioner questioned the basis of the selected detection level, and whether or not other variability adjustments (e.g., UPL analysis) sufficiently account for measurement imprecision. The EPA is denying the petition. The three times representative detection level approach was subject to notice and comment. The EPA explained its rationale for this approach in the proposed rule (75 FR 32021) and responded to comments received in the final rule (76 FR 15623, 76 FR 80611).

Issue: The approach used to set MACT floor limits for dioxin/furan emissions is flawed and the EPA should establish an isomer-specific approach.

The petitioner (WEPCO) requested that the EPA establish an isomer-specific approach for dioxin/furan emissions because the three times detection level approach for dioxin/furan emissions is flawed. The EPA is denying the petition. This approach was subject to notice and comment. Rationale and responses to comments on this approach were provided at (75 FR 32021, 32041, 76 FR 15623). Further, the methods for establishing a representative detection level for dioxin/furan have been revised to account for the sensitivity of individual isomers, see rationale provided at (76 FR 80606).

Issue: Incorporate a fuel variability factor for PM based on the ash content of the fuel used by best performing units.

The petitioners (WEPCO, CIBO) requested that the EPA incorporate a fuel variability factor for PM based on the ash content of the fuel used by best performing units. The MACT floor methodology was explained in the June 4, 2010 proposal which included fuel variability factors that did not reflect the ash content of the fuel. Therefore, the petitioner could have commented recommending that the EPA do so, and, in fact, comments were provided on this issue. The EPA is denying the petition for reconsideration on this issue because it does not demonstrate that it was impracticable to comment on the issue. Responses to comment on this topic were provided in RTC document, Volume 1, EPA–HQ–OAR–2002–0058–3289, see section ''MACT Floor Methodology: Fuel Analysis Variability''.

Issue: Allow energy assessors to determine the time needed to conduct assessment.

The petitioner (Washington Dept. of Ecology) requested that the EPA allow the energy assessor to determine the time needed to conduct the energy assessment. The EPA is denying the petition. The duration of energy assessments was subject to notice and comment and the duration remains up to the affected source. Specific concerns with maximum duration requirements included in the March 21, 2011 final rule were clarified in the December 23, 2011 proposed notice of reconsideration. (76 FR 80615)

Issue: The unit designed to burn gas 1 subcategory should allow for limited use of liquid fuels.

The petitioners (ACC, CEG, API, NPRA) requested that the EPA allow units in the Gas 1 subcategory for limited use of liquid fuels; for example, units with a federally enforceable permit on back up fuels or units burning 10 percent or less of its heat input from liquid fuels should qualify as gas 1 units. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on the issue. The EPA proposed definitions of the various subcategories, and petitioners had the opportunity to comment on those definitions, including the proposed definition of the Gas 1 subcategory which did allow for the limited use of liquid fuels. The EPA addressed comments received on this issue in the final rule (76 FR 15620).

Issue: The unit designed to burn gas 1 subcategory should automatically include other gaseous fuels such as petrochemical process gas and landfill gas.

The petitioners (ACC, AIF, WM) requested that the EPA redefine the unit designed to burn gas 1 subcategory to automatically include other gaseous fuels such as petrochemical process gas and LFG, especially when the LFG is routed to a treatment system prior to use or sale. The EPA proposed definitions of units designed to burn gas 1 and units designed to burn gas 2 (other), and therefore the petitioner had the opportunity to comment on these definitions and to recommend that other gases be included in the definition of the Gas 1 subcategory (75 FR 32017, 32065). The EPA addressed comments received on this issue in the final rule (76 FR 15638). Therefore, the EPA is denying the petition.

Issue: Reconsider the emission standards established for the unit designed to burn gas 2 subcategory.

Petitioners (AIF, CIBO, WM, CEG) requested that the EPA reconsider the emission standards for the unit designed to burn gas 2 subcategory in light of what they feel was a limited dataset and lack of data from a diverse set of fuel types. The EPA is denying the petition. The MACT floor methodology was open to notice and comment in the June 4, 2010 proposal. The EPA proposed emissions standards for this subcategory and the petitioners had an opportunity to comment on the proposed standards and the data on which the standards were based. The EPA further notes that the CAA requires that the MACT standards be based on the best performing sources for which the Administrator has emissions information.

Issue: Adjust the "metal process furnaces" subcategory definition to include any gas-fired process furnace.

The petitioners (AISI, ACCCI) requested that the EPA adjust the "metal process furnaces" subcategory definition to include any gas-fired process furnace. The EPA is denying the petition. The definition of the subcategory for metal process furnaces was subject to notice and comment. (75 FR 32064, 76 FR 15620).

Issue: The designed to burn rationale for subcategorization is arbitrary.

The petitioner (Sierra Club) alleged that the designed to burn rationale for subcategorization is arbitrary, especially considering the large number of co-fired units in the inventory. The EPA proposed subcategories based on boiler design, and the petitioner has not demonstrated that it was impracticable to comment on the issue. In fact, the petitioner did submit comments on the proposed rule opposing the EPA's proposed subcategorization approach. Therefore, the EPA is denying the petition.

Issue: The EPA should consider exempting units from NSR.

The petitioners (MSU, PSU, Purdue, Citizens Thermal Energy) requested that the EPA consider exempting units from NSR who switch fuels, install pollution controls, or construct energy efficiency projects to meet the requirements of this rule because complying with the rule requirements will trigger NSR. The EPA is denying the petition. The applicability of NSR is outside the scope of this rulemaking. Moreover, it was not impracticable to comment on this issue during the 2011 rulemaking, in fact, comments were submitted on this issue, to which the EPA responded. See RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2729.1, excerpt 17.

Issue: Remove the 10 percent penalty for sources opting to use the emission averaging compliance alternative.

The petitioners (AMP, MSU, PSU, Purdue, RPU, U.S. Sugar, Citizens Thermal Energy) requested that the EPA remove the 10 percent penalty for sources opting to use the emission averaging compliance alternative. The EPA is denying the petition. The EPA proposed an emissions averaging approach that included the 10 percent adjustment factor. (75 FR 32035) Therefore, the petition does not demonstrate that it was impracticable to comment on this issue. Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, see section "Emissions Averaging."

Issue: Allow emissions averaging across subcategories.

The petitioners (MSU, PSU, Purdue, RPU, Citizens Thermal Energy) requested that the EPA allow emissions averaging across subcategories. The EPA is denying the petition. The EPA proposed an emissions averaging approach that did not allow averaging across subcategories, and petitioners therefore had the opportunity to comment recommending that the EPA allow such averaging. Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–3213.1, excerpt 175.

Issue: Allow a source's actual heat input instead of the maximum design heat input to be used in the emissions averaging provisions.

The petitioner (CIBO) requested that the EPA allow a source's actual heat input instead of the maximum design heat input to be used in the emissions averaging provisions of the final rule. The EPA proposed an emissions averaging approach that was based on the maximum rated heat input capacity, and petitioners therefore had the opportunity to comment recommending that the EPA base the averaging on actual heat input. Therefore, the EPA is denying the petition.

Issue: Reduce stack testing frequency to once every five years to reduce burden on facilities.

The petitioners (ACC, CIBO, JELD–WEN) requested that the EPA reduce stack testing frequency to once every 5 years and rely on the extensive set of continuous parameter monitoring in order to reduce burden on facilities. The EPA is denying the petition. The EPA proposed to require stack testing every year. The petition does not demonstrate that it was impracticable to comment on this issue, and the petitioners could have submitted comments requesting less frequent stack testing.

Issue: Incorporate detailed fuel sampling procedures using incorporation by reference mechanisms instead of detailing sampling procedures in the regulatory language.

The petitioner (CIBO) requested that the EPA incorporate detailed fuel sampling procedures using incorporation by reference mechanisms and citing credible literature (e.g., American Society for Testing and Materials) instead of detailing sampling procedures in the regulatory language since sampling procedures are subject to change over time. The EPA is denying the petition because the petitioner has not demonstrated that it was impracticable to comment on this issue. The EPA proposed fuel sampling procedures in the regulatory text in the June 4, 2010 proposal, and the petitioner therefore had the opportunity to comment recommending its preferred approach.

Issue: Remove the advanced submittal requirement for site-specific fuel monitoring plans before each analysis.

The petitioner (UARG) requested that the EPA remove the advanced submittal requirement for site-specific fuel monitoring plans before each analysis, especially if monthly frequency is maintained. If the fuel monitoring plan requirement remains, the petitioner requests that the EPA remove the requirement to report things that might change, such as unanticipated fuel use (based on unanticipated fuel changes). The EPA is denying the petition and disagrees with the commenter. First, the EPA proposed a fuel monitoring plan, and petitioners had the opportunity to comment on the plan requirement. The final rule requires submittal of a fuel monitoring plan 60 days before demonstrating initial compliance. The rule does not require re-submittal of this plan before each monthly analysis, see 40 CFR section 63.7521(b)(1).

Issue: Allow EPA Method 5B to demonstrate compliance with PM emission limits.

The petitioner (UARG) requested that the EPA allow EPA Method 5B to demonstrate compliance with PM emission limits. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed methods to demonstrate compliance in the June 4, 2010 proposal and did not propose to allow Method 5B for PM compliance demonstrations. Therefore, the petitioner had the opportunity to submit comments recommending that the EPA allow the use of this method. For this

reason, the EPA is denying the petition on this issue.

Issue: Remove or make references to Methods 2, 2F, 2G and 4 optional.

The petitioner (UARG) requested that the EPA remove or make references to EPA Methods 2, 2F, 2G and 4 optional. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed methods to demonstrate compliance in the June 4, 2010 proposal and did not propose to make EPA Methods 2, 2F, 2G and 4 optional. Therefore, the petitioner had the opportunity to submit comments recommending that the EPA make the use of these methods optional. For this reason, the EPA is denying the petition on this issue.

Issue: Allow sources to petition for alternative PM monitoring requirements based on source-specific limitations.

The petitioner (CEG) requested that the EPA allow sources to petition for alternative PM monitoring requirements based on source-specific limitations (e.g., common stacks with more than one subcategory). The EPA is denying this petition because it is not of central relevance to this rulemaking. The General Provisions at 40 CFR 63.8 allow sources to petition the EPA for alternative monitoring plans. Therefore, no such provision is needed in this final rule.

Issue: Allow sources with overlapping CEMS regulations to comply with existing QA/QC plans or 40 CFR part 75 Appendices A and B.

The petitioners (CIBO, CMI) requested that the EPA allow sources with overlapping CEMS regulations to comply with existing QA/QC plans or 40 CFR part 75 Appendices A and B. The EPA is denying this petition because it is not of central relevance to this rulemaking.

Issue: No justification or discussion was provided on why the EPA selected 12 hours as the averaging time period and also why the EPA selected block averages instead of rolling averages.

The petitioner (Sierra Club) alleges that the EPA provided no justification or discussion explaining why the EPA selected 12 hours as the averaging time period and why the EPA selected block averages instead of rolling averages for parameter monitor. The petitioner requested that the EPA clarify that the averaging times for continuous parameter monitoring should be the same as the averaging times during the most recent performance test. Averaging times were open to notice and comment in the June 4, 2010 proposal. In the June 2010 proposal, we required that parameters be set based on 4-hour block averages during the compliance test, and that continuous compliance be demonstrated by monitoring 12-hour block average values for most parameters. We selected this averaging period to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits. Therefore, the EPA is denying the petition.

Issue: The EPA position regarding treatment of "out-of-control" and "maintenance" periods as deviations is not supported or explained.

The petitioner (UARG) alleges that the EPA position regarding treatment of "out-of-control" and "maintenance" periods as deviations is not supported or explained. The petitioner requested that the EPA revise the definition of "deviation" to be consistent with how deviation is treated with respect to CO CEMS and CPMS. The EPA is denying the petition. The definition of deviations was open to notice and comment in the June 4, 2010 proposal.

Issue: Require checks of pressure monitoring taps only if reading is abnormal.

The petitioner (CMI) requested that the EPA require checks of pressure monitoring taps only if reading is abnormal. The requirement to check pressure tap pluggage daily was open to notice and comment in the June 2010 proposal. In addition, the EPA is denying this petition because it is not of central relevance to this rulemaking.

Issue: The EPA has not sufficiently correlated emission limits to operating parameters and should not set enforceable limits on maximum and minimum control device operating parameters.

The petitioners (UARG, AMP, CIBO) alleges that the EPA has not sufficiently correlated emission limits to operating parameters and requested the EPA not to set enforceable limits on maximum and minimum control device operating parameters. One petitioner (CIBO) requested that the rule should allow sources to set their own ESP secondary voltage requirement based on load and coal quality since power consumption by an ESP is influenced by factors other than operating load, including ESP design, amount of PM collected, and resistivity of the PM. Other petitioners (UARG and AMP) also indicate that the limits set on control devices inhibit the flexibility to operate control devices with a margin of safety. The EPA is denying the petition. Operating limits were open to notice and comment in the June 4, 2010 proposal.

Issue: The EPA should delay incorporating PS 17 in this rule until the revisions for PS 17 are completed.

The petitioner (UARG) requested that the EPA delay incorporating PS 17 in this rule, which outlines how to select and install CPMS, until the revisions for PS 17 are completed.

The EPA is denying this petition. The final rule did not incorporate PS 17, or any other PS, in the provision regarding selection and installation of CPMS and ongoing quality assurance of data from CPMS. Comments related to revising PS 17 are outside the scope of this rulemaking. (RTC document, Chapter 11, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2960.1, excerpt 150).

Issue: The EPA should not set an enforceable operating limit on opacity.

The petitioner (UARG) alleged that there is insufficient correlation between opacity and PM emissions and requested that the EPA not set an enforceable operating limit on opacity. The EPA is denying the petition. The EPA proposed opacity limits in the June 4, 2010 proposal and the petitioner therefore had the opportunity to comment on the proposed limits, including comments requesting that no limit be established.

Issue: Update outdated BLDS Guidance.

The petitioner (UARG) requested that the EPA update the outdated BLDS Guidance that is currently incorporated by reference. The EPA is denying this petition. The current guidance document is the most recent guidance available and comments related to revising the guidance document are outside the scope of this rulemaking. (RTC document, Chapter 11, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2997.1, excerpt 10).

Issue: The EPA should reconsider emission limits for HCl on coal-fired boilers using a hot-side ESP for particulate control.

The petitioners (MSU, PSU, Purdue, Citizens Thermal Energy) requested that the EPA reconsider emission limits for HCl on coal-fired boilers using a hot-side ESP for particulate control. The petitioners are unaware of any HCl control devices that are compatible with a hot-side ESP. The EPA is denying the petition. The basis for subcategorization was subject to notice and comment. The EPA did not propose a separate subcategory for such units, and the petitioner could have commented recommending that the agency do so. (75 FR 32012, 76 FR 15617–18, 76 FR 80607) Further, the EPA disagrees with the petitioner that the subcategories

could be based on the level of controls installed on the unit.

Issue: The EPA should change electronic reporting requirements to avoid WebFIRE and ERT shortcomings.

The petitioner (UARG) requested that the EPA change the electronic reporting requirements to avoid WebFIRE and ERT shortcomings. The petitioner requested that to meet the EPA's obligations under the Paperwork Reduction Act the EPA specify each individual data item requested in the ERT. The petitioner also requests that the EPA explain how the ERT electronic signature mechanisms will meet the requirements of the Cross-Media Electronic Reporting Rule.

The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed to require the use of the ERT and WebFIRE, and the petitioner therefore had the opportunity to comment on any concerns with the proposed approach.

Issue: Eliminate gas curtailment notification requirements or adjust the frequency of these notifications to be consistent with the reporting requirements in the Title V program.

The petitioner (AIF) requested that the EPA eliminate the gas curtailment notification requirements or adjust the frequency of these notifications to be consistent with the semi-annual reporting requirements in the Title V program. The EPA is denying the petition. Reporting requirements were open to notice and comment in the June 4, 2010 proposal.

Issue: Allow facilities to become area or synthetic minor sources instead of installing controls.

The petitioner (GPSP) requested that the EPA allow facilities to become area or synthetic minor sources instead of installing controls. The EPA is denying the petition. Whether or not sources elect to become area or synthetic minor sources is not of central relevance to this rulemaking, as nothing in this rule affects whether or how a source can become a synthetic minor source (RTC document, EPA–HQ–OAR–2002–0058–3289, Volume 1, DCN EPA–HQ–OAR–2002–0058–3176.2, excerpt 4).

VI. Impacts of This Final Rule

A. What are the incremental air impacts?

Table 4 of this preamble illustrates, for each basic fuel subcategory, the total emissions reductions achieved by the final amended rule (i.e., the difference in emissions between a boiler or process heater controlled to the amended floor level of control and boilers or process heaters at the current baseline) for new and existing sources. Nationwide emissions of selected HAP (i.e., HCl, HF, mercury, metals, and VOC) will be reduced by 44,300 tpy. This is an incremental increase of 4,000 tpy in HAP reductions compared to the estimates in the March 2011 final rule. This increase is due mainly to changes in the inventory (336 units were added since the March 2011 inventory). Excluding the changes in the inventory, the amendments to the regulatory provisions themselves resulted in a decrease of 1,100 tpy of estimated reductions, part of this incremental reduction in HAP is contributed to edits to the baseline emission data received since the March 2011 final rule, as well as changes to the subcategories and emission limits as a result of this amended rule. The amendments to the final rule are expected to result in an additional 4,600 tpy of reductions in HCl emissions. The amendments are also expected to have a modest effect on mercury, estimated to range from a slight decrease of 0.12 tpy up to a slight increase of 0.96 tpy in emission reductions as a result of the changes to the regulatory requirements. Reductions in emissions of filterable PM will decrease by 18,500 tpy due to the final amended rule. Reductions in emissions of non-mercury metals (i.e., antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) will decrease by 260 tpy. In addition, the amendments are estimated to result in an additional 50,100 tpy of reductions in SO_2 emissions. A discussion of the methodology used to estimate emissions, emissions reductions, and incremental emission reductions is presented in "Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source" in the docket.

TABLE 4—SUMMARY OF TOTAL EMISSIONS REDUCTIONS FOR THE FINAL AMENDED RULE

[tons/yr]

Source	Subcategory	HCl	PM	Non mercury metals [a]	Mercury [b]	VOC
Existing Units	Limited Use	1	2	0.42	2.1E–04	0.48
	Solid units	36,737	21,367	147	0.4 to 1.5	1,619
	Liquid units	2,143	9,434	2,315	0.9 to 1	620
	Non-Continental Liquid units	35	3	1	0.01 to 0.02	23
	Gas 1 (NG/RG) units	20	117	0.3	0.01	88
	Gas 1 Metallurgical Furnaces	0.4	3	0.02	0.001	27
	Gas 2 (other) units	4	8	0.06	3.8E–03 to 4.6E–03.	40
New Units	Solid units	0	351	5	0.02	0
	Liquid units	0	0	0	0	0
	Gas 1 units	0	0	0	0	0
	Gas 1 Metallurgical Furnaces	0	0	0	0	0
	Gas 2 (other) units	0	0	0	0	0

[a] Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

[b] Mercury reductions are presented as a range due to adjustments on reported fractions and limits of detection. See memorandum entitled "Revised (March 2012) Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source" for a description of the two methods for estimating mercury reductions.

B. What are the incremental water and solid waste impacts?

The EPA estimated the additional water usage that would result from installing wet scrubbers to meet the amended emission limits for HCl would be 556 million gallons per year for existing sources compared to the current baseline. In addition to the increased water usage, an additional 160 million gallons per year of wastewater would be produced for existing sources. Only half of these incremental changes are due to changes in the regulatory provisions. The other half is due to changes in the number of identified existing units and projected new units. The annual costs of treating the additional wastewater are $1.2 million. These additional costs are accounted for in the incremental control cost estimates.

The EPA estimated the additional solid waste that would result due to the amendments to be 138,000 tpy, with nearly all due to changes in the regulatory provisions. Solid waste is generated from flyash and dust captured in PM and mercury controls as well as from spent carbon that is injected into exhaust streams or used to filter gas streams. The costs of handling the additional solid waste generated are $5.8 million. These costs are also accounted for in the incremental control costs estimates.

A discussion of the methodology used to estimate incremental impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

C. What are the incremental energy impacts?

The EPA estimated that the March 2011 final rule would result in an increase of about 1.4 billion kWh/yr in national energy usage from the electricity required to operate control devices, such as wet scrubbers, electrostatic precipitators and fabric filters which are expected to be installed to meet the final rule. The amendments are expected to decrease energy usage by a net 143 million kWh/yr compared to the March 2011 rule. These reductions are driven by the regulatory provisions of these amendments. Additionally, the EPA expects these amendments will result in a decrease of 4.4 million MMBtu/yr in fuel savings, compared with the estimates in the March 2011 final rule.

D. What are the incremental cost impacts?

For these final amendments, we estimated the incremental difference between the national costs impacts for the final amended rule and the March 2011 final rule. First, we determined the control measures, work practices, and monitoring and testing requirements that would be required by boilers and process heaters located at major source facilities to comply with the final amended rule. To estimate the national cost impacts of the final amended rule for existing sources, we used the identical methodology used to estimate the cost impacts for the March 2011 final rule with one exception. In this revised analysis, it was assumed that several liquid fuel units that reported natural gas firing capability would switch to natural gas as a compliance option instead of installing add-on controls to demonstrate compliance with the emission limits. Thus, the only costs to these units would be the tune-up work practice costs. A discussion of the methodology used to estimate cost impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

The resulting total national cost impact of the final amended rule is $4.7 billion in capital expenditures and $1.5 billion per year in total annual costs, considering fuel savings. The total capital expenditures are slightly lower than estimated for the March 2011 final rule, but the total annual costs are slightly higher than estimated for the March 2011 final rule. See 76 FR 15651. The total capital and annual costs include costs for control devices, work practices, testing and monitoring.

In order to determine the incremental cost impacts of the amended requirements and emission limits, we first estimated the cost impacts of the additional existing boilers and process heaters added to the Boiler MACT inventory database since promulgation of the March 2011 final rule and the revised number of new boilers and process heaters that could be potentially constructed. Since the March 2011 final rule, we became aware of 72 major source facilities that were not previously in the Boiler MACT inventory database. Adding the boilers and process heaters located at these newly identified major source facilities resulted in 73 additional coal-fired units, 32 additional biomass-fired units, 82 additional oil-fired units, and 149 additional gas-fired units. Our revised number of new boilers and process heaters included 82 additional biomass units, 1,728 additional gas 1 units and 13 fewer liquid units.

The resulting cost impact for these additional existing and new boilers and process heaters is $1.0 billion in capital expenditures and $0.31 billion per year in total annual costs, considering fuel savings.

Therefore, discounting the added costs for the additional boilers and process heaters included in the costs analysis, the estimated incremental cost impacts for these amended requirements on existing and new boilers and process heaters are $1.0 billion in capital expenditures and $0.13 billion per year in total annual costs less than the costs estimated in the March 2011 rule.

Table 5 of this preamble shows the total capital and annual cost impacts of the final amended rule for each subcategory. Costs include testing and monitoring costs, but not recordkeeping and reporting costs.

TABLE 5—SUMMARY OF TOTAL CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES FOR THE FINAL AMENDED RULE

Source	Subcategory	Estimated/ projected number of affected units	Capital costs (10^6 $)	Testing and monitoring annualized costs (10^6 $/yr)	Annualized cost (10^6 $/yr) (considering fuel savings)
Existing Units	Coal units	621	2,554	46	904
	Biomass units	502	405	29	109
	Heavy Liquid units	319	761	5.4	221
	Light Liquid units	615	712	4.2	166
	Non-Continental Liquid units	21	62	0.8	17
	Gas 1 (NG/RG) units	11,929	77	0.9	(295)

TABLE 5—SUMMARY OF TOTAL CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES FOR THE FINAL AMENDED RULE—Continued

Source	Subcategory	Estimated/ projected number of affected units	Capital costs (10^6 $)	Testing and monitoring annualized costs (10^6 $/yr)	Annualized cost (10^6 $/yr) (considering fuel savings)
	Gas 2 (other) units	129	138	2.3	58
Energy Assessment	ALL	1,700 (Facilities).	N/A	N/A	28
New Units	Coal units	0	0	0	0
	Biomass units	82	381	5.6	[a] 99
	Liquid units	0	0	0	0
	Gas 1 (NG/RG) units	1,762	11	0	[a] 5.1
	Gas 2 (other) units	0	0	0	0

[a] Total annualized costs for new units do not account for fuel savings since no fuel savings are estimated in the first year for new units.

Potential control device cost savings and increased recordkeeping and reporting costs associated with the emissions averaging provisions in the final rule are not accounted for in either the capital or annualized cost estimates.

A discussion of the methodology used to estimate cost impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

E. What are the economic impacts?

The EPA analyzed the economic impacts of this final amended rule using the methodology that was discussed in the March 2011 final rule RIA and in the preamble to the March 2011 final rule. See FR 76 15651. The market impact results are very similar to the results presented in the March 2011 final rule and the RIA. The agency's economic model suggests the average national price increases for industrial sectors are less than 0.01 percent, while average annual domestic production may fall by less than 0.01 percent.

Because of higher domestic prices, imports slightly rise. The results for sales tests for small businesses were somewhat reduced than those calculated for the March 2011 final rule. For the sales tests using small companies identified in the Combustion Survey, the mean cost to receipts dropped from 4 percent in the RIA to 3 percent for this final amended rule and the median was 0.2 percent for the RIA and also 0.2 percent for this final amended rule. The number of parent companies with sales tests exceeding 3 percent dropped from 8 in the RIA to 5 for this final amended rule. There was no change in the results for small public entities. Median cost is still about $1.1 million and representative small major public entities would have cost-to-revenue ratios above 10 percent. The change in employment estimates between the RIA and the final amended rule is minimal. In the RIA for the March 2011 final rule, we estimated employment changes ranging between −3,100 to +6,500 employees, with a central estimate of +1,700. For this final amended rule we estimate employment changes ranging between −2,600 to +5,400 employees, with a central estimate of +1,400. These estimated annual employment changes compared to the baseline employment, and are for the time period for which the annualized cost applies (2015 to 2029).

F. What are the benefits of this final rule?

We calculated health benefits using the methodology described in the RIA prepared for the March 21, 2011 final rule. We incorporated the revised emission reductions estimated for this reconsideration final rule into the analysis. We were unable to estimate the benefits from reducing exposure to HAP and ozone, ecosystem impairment and visibility impairment, including reducing 180,000 tons of carbon monoxide, 39,000 tons of HCl, 500 tons of HF, 2,500 tons of other metals and 3,100 to 5,300 pounds of mercury. Please refer to the full description of the unquantified benefits as well as technical details of the analysis and its limitations and uncertainties in the final Boiler RIA (March 2011). These monetized benefits are approximately 23 percent higher than the March 2011 final rule benefits due to the increase in SO_2 emission reductions associated with the additional units affected by the rule and the revised HCl limit. We estimate the total monetized benefits of this final regulatory action to be $27 billion to $67 billion at a 3 percent discount rate and $25 to $61 billion at a 7 percent discount rate. All estimates are for the implementation year (2015) in 2008$. A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is provided in Table 6 of this preamble. A summary of the avoided health incidences is provided in Table 7 of this preamble.

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT

[millions of 2008$] [a b]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
$PM_{2.5}$-related benefits			
Direct $PM_{2.5}$	14,139	$1,200 to $2,900	$1,100 to $ $2,700
SO_2	572,000	$26,000 to $64,000	$24,000 to $61,000

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT—Continued

[millions of 2008$] [a b]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
Total		$27,000 to $67,000	$25,000 to $61,000.

[a] All estimates are for the implementation year (2015), and are rounded to two significant figures so numbers may not sum across rows. All fine particles are assumed to have equivalent health effects because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Benefits from reducing hazardous air pollutants (HAP) are not included. These estimates do not include energy disbenefits valued at $24 million (using a 3 percent discount rate). These benefits reflect existing boilers and new boilers anticipated to come on-line by 2015.

[b] There are some slight differences in the emission reductions used in the RIA and those used in the air impacts section of this preamble due to some late changes in the data that were received after the RIA was completed. Refer to the memoranda "Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source" for a discussion of the differences.

TABLE 7—SUMMARY OF THE AVOIDED HEALTH INCIDENCES FOR THE FINAL BOILER MACT [a]

	Avoided health incidences
Premature Mortality	3,000–7,900
Morbidity	
Chronic Bronchitis	2,000
Acute Myocardial Infarction	5,000
Hospital Admissions, Respiratory	750
Hospital Admissions, Cardiovascular	1,600
Emergency Room Visits, Respiratory	3,000
Acute Bronchitis	4,600
Work Loss Days	390,000
Asthma Exacerbation	51,000
Minor Restricted Activity Days	2,300,000
Lower Respiratory Symptoms	55,000
Upper Respiratory Symptoms	41,000

[a] All estimates are for the implementation year (2015), and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Benefits from reducing HAP are not included. These benefits reflect existing boilers and new boilers anticipated to come online by 2015.

G. What are the incremental secondary air impacts?

For units adding controls to meet the amended emission limits, we anticipate very minor secondary air impacts. The combustion of fuel needed to generate additional electricity would yield slight increases in emissions, including NO_X, CO, PM and SO_2 and an increase in CO_2 emissions. Since NO_X and SO_2 are covered by capped emissions trading programs and methodological limitations prevent us from quantifying the change in CO and PM, we do not estimate an increase in secondary air impacts for this final rule from additional electricity demand. We do estimate greenhouse gas impacts, which result from increased electricity consumption, to be 859,200 tpy from existing units and 79,700 tpy from new units. This is 19,200 tpy less than the estimated greenhouse gas impacts associated with the March 2011 final rule.

VII. Statutory and Executive Order Reviews

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

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

The EPA did prepare a new RIA for this action. The EPA prepared an assessment of the changes in the costs and benefits of this final rule compared to the costs and benefits associated with the March 21, 2011, final rule. Overall, the costs and impacts are estimated to be similar to the costs and impacts associated with the previous final rule, although the distribution is somewhat different and the number of affected units in the inventory has increased by about 302 units. When comparing the costs using only those sources that were part of the final rule inventory, the costs have decreased. The EPA re-ran the multimarket model to assess changes in economic impacts, and this analysis confirmed that the overall economic impacts are similar to the previous final rule. The benefits are projected to increase by about 20 percent because of the increase in the estimated SO_2 reductions. A summary of the costs and benefits of the previous final rule is provided in the preamble to the previous final rule (*see* 76 FR 15658) and the detailed analysis for the previous final rule is provided in the RIA for the previous final rule. In addition, memoranda are provided in the docket to document the changes in costs, economic impacts, and benefits associated with this final rule, shown in Table 8.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Total Monetized Benefits [2]	$27,000 to $67,000	$24,000 to $61,000.
Total Social Costs [3]	$1,400 to $1,600	$1,400 to $1,600.
Net Benefits	$26,000 to $65,000	$23,200 to $59,000.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015—Continued

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Non-monetized Benefits	Health effects from exposure to HAP (39,000 tons of HCl, 500 tons of HF, 3,100 to 5,300 pounds of mercury, and 2,500 tons of other metals). Health effects from exposure to other criteria pollutants (180,000 tons of CO and 572,000 tons of SO_2). Ecosystem effects. Visibility impairment.	

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures.

[2] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as directly emitted particles, SO_2, and NO_X and reducing exposure to ozone through reductions of VOC. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Monetized benefits are shown as a range from Pope et al. (2002) to Laden et al. (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to support the development of differential effects estimates by particle type. These estimates include the energy disbenefits valued at $24 million (using the 3 percent discount rate), which do not change the rounded totals. CO_2-related disbenefits were calculated using the "social cost of carbon", which is discussed further in the RIA.

[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

B. Paperwork Reduction Act

The OMB has approved the information collection requirements contained in the March 21, 2011 final rule under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0551. The EPA has updated the supporting statement to reflect the final inventory and burden estimates associated with this action since some of the monitoring, recordkeeping and reporting requirements have changed since the March 21, 2011 final rule. These revised estimates have been sent to OMB for review and approval.

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 will require maintenance inspections of the control devices but will not require any notifications or reports beyond those required by the General Provisions aside from a notification of intent to commence burning solid waste materials and notification of alternative fuel use for those units that are in the Gas 1 subcategory but burn liquid fuels for periodic testing, or during periods of gas curtailment or gas supply emergencies. The recordkeeping requirements require only the specific information needed to determine compliance.

The revised annual monitoring, reporting and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $95.3 million which is about the same as estimated for the March 2011 final rule. This includes 323,130 labor hours per year at a total labor cost of $30.6 million per year, and total non-labor capital costs of $64.7 million per year. This estimate includes initial and annual performance test, conducting and documenting an energy assessment, conducting fuel specifications for Gas 1 units, repeat testing under worst-case conditions for solid fuel units, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications and recordkeeping. Monitoring, testing, tune-up and energy assessment costs and cost were also included in the cost estimates presented in the control costs impacts estimates in section VI.D of this preamble. The total burden for the federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 100,608 hours per year at a total labor cost of $5.3 million 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. In addition, the 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 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.[1] The RFA also allows an agency to "consider a series of closely related rules as one rule for the purposes of sections" 603 (initial regulatory flexibility analysis) and 604 (final regulatory flexibility analysis) in order to avoid "duplicative action." 5 U.S.C. § 605(c). This final rule is closely related to the final major source rule, which the EPA signed on February 21, 2011. The EPA prepared a final regulatory flexibility analyses in connection with the major source rule. Therefore,

[1] 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 according to Small Business Administration (SBA) size standards by the North American Industry Classification System category of the owning entity. The range of small business size standards for the affected industries ranges from 500 to 1,000 employees, except for petroleum refining and electric utilities. In these latter two industries, the size standard is 1,500 employees and a mass throughput of 75,000 barrels/day or less, and 4 million kilowatt-hours of production or less, respectively; (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 § 605(c), the EPA is not required to complete a final regulatory flexibility analysis for this rule.

The EPA has been concerned with potential small entity impacts since it began developing the major source rule. The EPA conducted outreach to small entities and, pursuant to § 609 of RFA, convened a Small Business Advocacy Review Panel to obtain advice and recommendations from small entity representatives.

Pursuant to the RFA, the EPA used the Panel's report and prepared both an initial regulatory flexibility analysis and a final regulatory flexibility analysis in connection with the closely related major source rule. Convening an additional Panel and preparing an additional final regulatory flexibility analysis would be procedurally duplicative and is unnecessary given that the issues here are within the scope of those considered by the Panel. In addition, this final action would decrease capital and annualized costs on small entities by about 3 percent and 10 percent, respectively, relative to the closely related final rule.

D. Unfunded Mandates Reform Act

Title II of the UMRA of 1995, 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 the EPA regulatory proposals with significant Federal intergovernmental mandates and must inform, educate, and advise small governments on compliance with the regulatory requirements.

Both this rule and the March 21, 2011 final rule 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. Accordingly, the EPA prepared under section 202 of the UMRA a written statement for the final rule. This final rule also 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 one year. The discussion below has been updated to reflect the changes.

1. Statutory Authority

As discussed in the March 21, 2011, final rule, the statutory authority for this final rulemaking is section 112 of the CAA. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. Section 112(b) of the CAA 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.

Section 112(d) of the CAA 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 boilers and process heaters located at major sources of HAP emissions.

2. Social Costs and Benefits

The regulatory impact analysis prepared for the March 21, 2011 final rule, which we have revised for this final rule, including the agency's assessment of costs and benefits, is detailed in the "Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)" and in the "Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources" in the docket. Based on estimated compliance costs associated with this final rule and the predicted change in prices and production in the affected industries, the estimated social costs of this rule are $1.4 to 1.6 billion (2008 dollars).

It is estimated that 3 years after implementation of this final rule, HAP would be reduced by 45,000 tpy, including reductions in HCl, hydrogen fluoride, metallic HAP including mercury, and several other organic HAP from boilers and process heaters. Studies have determined a relationship between exposure to 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, there are significant annual reductions in fine particulate matter ($PM_{2.5}$) and in SO_2 that would occur, including 25 thousand tons of $PM_{2.5}$ and 558 thousand tons of SO_2. These reductions occur within 3 years after the implementation of the final regulation 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) are 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). While we are unable to monetize the benefits associated with the HAP emissions 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 2015 associated with the implementation of the final regulatory action range from $27 billion (2008 dollars) to $67 billion (2008 dollars) when using a 3 percent discount rate (or from $25 billion (2008 dollars) to $61 billion (2008 dollars) when using a 7 percent discount rate). This estimate, at a 3 percent discount rate, is about $25 billion (2008 dollars) to $65 billion (2008 dollars) higher than the estimated social costs shown earlier in this section. The general approach used to value benefits is discussed in more detail earlier in this preamble. For more detailed information on the benefits estimated for the rulemaking, refer to the RIA and the memos updating the impacts and benefits 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 final rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of the 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. See the results of the "Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)."

4. 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 Final Industrial Boilers and Process Heaters MACT (2011)" and a memoranda that are included in the docket, entitled "Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources which update the RIA analyses. 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 there will be a small impact on prices and output, and little impact on communities that may be affected by this final rule. In addition, there should be little impact on energy markets (in this case, coal, natural gas, petroleum products and electricity). Hence, the potential impacts on the categories mentioned above should be small.

5. Consultation With Government Officials

The UMRA requires that we describe the extent of the agency's prior consultation with affected state, local and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, section 203 of the UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a final rule. We consulted with state and local air pollution control officials during the development of the final rule. We have also held meetings on this final rule with many of the stakeholders from numerous individual companies, institutions, environmental groups, consultants and vendors, labor unions and other interested parties. We have added materials to the docket to document these meetings.

Consistent with section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the docket.

The regulatory alternative upon which the emission limits in this final rule are based represents the MACT floors for all subcategories and, as a result, it is the least costly and least burdensome alternative.

This rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by this final rule, the impacts are not expected to be significant. Therefore, this final rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This final rule will not impose direct compliance costs on state or local governments, and will not preempt state law. 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 effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

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 Order has the potential to influence the regulation. This action is not subject to EO 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. For the March 21, 2011, final rule, we estimated a 0.05 percent price increase for the energy sector and a −0.02 percent percentage change in production. We estimated a 0.09 percent increase in energy imports. For more information on the estimated energy effects, please refer to the "Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)." The analysis is available in the public docket. While we did not recreate the RIA for this final action, the energy impacts for existing sources decreased slightly, and the energy impacts for new source increased due to the increased number of new sources that is now projected. Overall, the projected energy use increased slightly but would not change the analysis that was conducted for the previous final rule. Therefore, we conclude that this final rule when implemented is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA, Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs the EPA to use 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 the OMB, explanations when the agency decides not to use available and applicable VCS.

This action does not involve any new technical standards from those contained in the March 21, 2011 final rule. Therefore, the EPA did not consider the use of any VCS. See 76 FR 15660–15662 for the NTTAA discussion in the March 21, 2011 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.

For the March 2011 final rule, the EPA determined that the rule would 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. Compared to the previous final rule, while the amendments are somewhat less stringent for some subcategories of units and more stringent for some others, the overall increased health benefits demonstrate that the conclusions from the environmental justice analysis conducted for the previous final rule are still valid. Therefore, the EPA has determined this final rule will not have disproportionately high and adverse human or environmental effects on minority or low-income populations.

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). With the exception of the May 18, 2011 (76 FR 28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) being lifted January 31, 2013, this rule will be effective April 1, 2013.

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: December 20, 2012

Lisa P. Jackson,

Administrator.

For the reasons cited 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 for part 63 continues to read as follows:

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

■ 2. Effective January 31, 2013, the May 18, 2011 (76 FR 28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) is lifted.

Subpart A—[Amended]

■ 3. Section 63.14 is amended by:
■ a. Revising paragraphs (b)(19), (b)(23), (b)(35), (b)(40), (b)(69), and (b)(70).
■ b. Removing and reserving paragraph (b)(53).
■ c. Adding paragraphs (b)(46), (b)(55), and (b)(76) through (83).
■ d. Adding paragraphs (p)(12) through (20).
■ e. Adding paragraph (r).

The revisions and additions read as follows:

§ 63.14 Incorporations 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) and table 6 to subpart DDDDD.

* * * * *

(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) and table 6 to subpart DDDDD.

* * * * *

(35) 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 1 to subpart DDDDD of this part, table 2 to subpart DDDDD of this part, table 5 to subpart DDDDD, table 11 to subpart DDDDD of this part, table 12 to subpart DDDDD of this part, table 13 to subpart DDDDD of this part, and table 4 to subpart JJJJJJ of this part.

* * * * *

(40) ASTM D396–10 Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for § 63.7575 and § 63.11237.

* * * * *

(46) ASTM D4606–03 (2007), Standard Test Method for Determination of Arsenic and Selenium in Coal by the Hydride Generation/Atomic Absorption Method, approved October 1, 2007, IBR approved for table 6 to subpart DDDDD.

* * * * *

(55) ASTM D6357–11, Test Methods for Determination of Trace Elements in Coal, Coke, and Combustion Residues from Coal Utilization Processes by Inductively Coupled Plasma Atomic Emission Spectrometry, approved April 1, 2011, IBR approved for table 6 to subpart DDDDD.

* * * * *

(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) and table 6 to subpart DDDDD.

(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) and table 6 to subpart DDDDD.

* * * * *

(76) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, approved July 15, 2011, IBR approved for § 63.7575 and § 63.11237.

(77) ASTM D975–11b, Standard Specification for Diesel Fuel Oils, approved December 1, 2011, IBR approved for § 63.7575.

(78) ASTM D5864–11 Standard Test Method for Determining Aerobic Aquatic Biodegradation of Lubricants or Their Components, approved March 1, 2011, IBR approved for table 6 to subpart DDDDD.

(79) ASTM D240–09 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, approved July 1, 2009, IBR approved for table 6 to subpart DDDDD.

(80) ASTM D4208–02 (2007) Standard Test Method for Total Chlorine in Coal by the Oxygen Bomb Combustion/Ion Selective Electrode Method, approved May 1, 2007, IBR approved for table 6 to subpart DDDDD.

(81) ASTM D5192–09 Standard Practice for Collection of Coal Samples from Core, approved June 1, 2009, IBR approved for table 6 to subpart DDDDD.

(82) ASTM D7430–11ae1, Standard Practice for Mechanical Sampling of Coal, approved October 1, 2011, IBR approved for table 6 to subpart DDDDD.

(83) ASTM D6883–04, Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles, approved June 1, 2004, IBR approved for table 6 to subpart DDDDD.

* * * * *

(p) * * *

(12) Method 5050 (SW–846–5050), Bomb Preparation Method for Solid Waste, Revision 0, September 1994, in

EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition IBR approved for table 6 to subpart DDDDD.

(13) Method 9056 (SW–846–9056), Determination of Inorganic Anions by Ion Chromatography, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(14) Method 9076 (SW–846–9076), Test Method for Total Chlorine in New and Used Petroleum Products by Oxidative Combustion and Microcoulometry, Revision 0, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(15) Method 1631 Revision E, Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Absorption Fluorescence Spectrometry, Revision E, EPA–821–R–02–019, August 2002, IBR approved for table 6 to subpart DDDDD.

(16) Method 200.8, Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma—Mass Spectrometry, Revision 5.4, 1994, IBR approved for table 6 to subpart DDDDD.

(17) Method 6020A (SW–846–6020A), Inductively Coupled Plasma-Mass Spectrometry, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(18) Method 6010C (SW–846–6010C), Inductively Coupled Plasma-Atomic Emission Spectrometry, Revision 3, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(19) Method 7060A (SW–846–7060A), Arsenic (Atomic Absorption, Furnace Technique), Revision 1, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(20) Method 7740 (SW–846–7740), Selenium (Atomic Absorption, Furnace Technique), Revision 0, September 1986, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

* * * * *

(r) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332–8686, *http://www.tappi.org.*

(1) TAPPI T 266, Determination of Sodium, Calcium, Copper, Iron, and Manganese in Pulp and Paper by Atomic Absorption Spectroscopy (Reaffirmation of T 266 om-02), Draft No. 2, July 2006, IBR approved for table 6 to subpart DDDDD.

(2) [Reserved]

Subpart DDDDD—[Amended]

■ 4. Section 63.7485 is revised to read as follows:

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

■ 5. Section 63.7490 is amended by adding paragraph (e) to read as follows:

§ 63.7490 What is the affected source of this subpart?

* * * * *

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

■ 6. Section 63.7491 is amended by:
■ a. Revising the introductory text.
■ b. Revising paragraph (a).
■ c. Revising paragraph (c).
■ d. Revising paragraph (h)
■ e. Revising paragraph (i).
■ f. Revising paragraph (m).
■ g. Revising paragraph (n).

The revisions read as follows:

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

* * * * *

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

* * * * *

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

* * * * *

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

* * * * *

■ 7. Section 63.7495 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (b).
■ c. Adding paragraphs (e), (f), and (g).

The revisions and additions read as follows:

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i).

* * * * *

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of § 60.2145(a)(2) and (3) or § 60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2013, you must

be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

■ 8.Section 63.7499 is amended by revising paragraphs (d) and (f) through (l) and adding paragraphs (p) through (u) to read as follows:

§ 63.7499 What are the subcategories of boilers and process heaters?

* * * * *

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

* * * * *

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

* * * * *

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

■ 9. Section 63.7500 is amended by:

■ a. Revising paragraph (a).

■ b. Revising paragraph (c).

■ c. Adding paragraph (d).

■ d. Adding paragraph (e).

■ e. Adding paragraph (f).

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and before January 31, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), 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.

* * * * *

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.

■ 10. Section 63.7501 is revised to read as follows:

§ 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in

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

(1) The violation:

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

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

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

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

(2) Repairs were made as expeditiously as possible when a violation occurred; and

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

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

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

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

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

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

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

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in § 63.7500 of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 11. Section 63.7505 is amended by:

■ a. Revising paragraph (a).

■ b. Revising paragraph (c).

■ c. Revising paragraphs (d) introductory text, (d)(1) introductory text, and (d)(1)(iii).

§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

* * * * *

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits (including the use of CPMS), or with a CEMS, or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

* * * * *

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

* * * * *

■ 12. Section 63.7510 is revised to read as follows:

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to

§ 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

■ 13. Section 63.7515 is revised to read as follows:

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to

demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra low sulfur liquid fuel, you do not need to conduct further performance tests if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

■ 14. Section § 63.7520 is amended by revising paragraphs (a), (c), (d), and (e) and adding paragraph (f) to read as follows:

§ 63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

* * * * *

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A–7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average 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.

■ 15. Section 63.7521 is revised to read as follows:

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in

Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

■ 16. Section § 63.7522 is revised by:
■ a. Revising paragraphs (a) through (d).
■ b. Revising paragraphs (e)(1) and (2).
■ c. Revising paragraphs (f) introductory text and (f)(1) and (2).
■ d. Revising paragraphs (g) introductory text, (g)(2)(i), (g)(2)(iv), (g)(2)(vi)(B), (g)(3) introductory text, (g)(4) introductory text, and (g)(4)(ii).
■ e. Revising paragraph (h).
■ f. Revising paragraph (i).
■ g. Revising paragraph (j)(1).
■ h. Revising paragraph (k).

The revisions read as follows:

§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on

January 31, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on January 31, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are operating following the compliance date specified in § 63.7495.

(e) * * *

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq. 1a)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 1b)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 1c)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sm \times Cfi) \div \sum_{i=1}^{n} (Sm \times Cfi) \qquad \text{(Eq. 2)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.
Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.
1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual steam generation for the month if you are complying with the emission limits on a electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3a)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.
Hb = The heat input for that calendar month to unit, i, in units of million Btu.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 3b)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.
So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 3c)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.
Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in § 63.7575.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sa \times Cfi) \div \sum_{i=1}^{n} (Sa \times Cfi) \qquad \text{(Eq. 4)}$$

Where:
AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million

Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

* * * * *

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

* * * * *

(2) * * *

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

* * * * *

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in § 63.7520;

* * * * *

(vi) * * *

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

* * * * *

(3) The Administrator shall review and approve or disapprove the plan according to the following criteria:

* * * * *

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

* * * * *

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

* * * * *

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategories, each of which vents 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.

(j) * * *

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.

Hi = Heat input from unit i, MMBtu.

* * * * *

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

■ 17. Section 63.7525 is amended by:

■ a. Revising paragraph (a)

■ b. Revising paragraph (b).

■ c. Revising paragraph (c) introductory text.

■ d. Revising paragraphs (d) introductory text and paragraphs (d)(1) through (d)(4).

■ e. Revising paragraph (e)(2).

■ f. Revising paragraph (e)(3).

■ g. Revising paragraph (f)(2).

■ h. Revising paragraph (j).

■ i. Revising paragraph (k).

■ j. Adding paragraph (l).

■ k. Adding paragraph (m).

The revisions and additions read as follows:

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in paragraphs (a)(1) through (7) of this section.

(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. The CO and oxygen levels shall be monitored at the same location at the outlet of the boiler or process heater.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, the site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in § 63.8(e) and

according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A–4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Complete a minimum of one cycle of CO and oxygen CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen data concurrently. Collect at least four CO and oxygen CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19–19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A–7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, certify, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(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 PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(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 of detecting and responding to PM concentrations of no greater than 0.5 milligram per actual cubic meter.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A–3 or Method 17 at 40 CFR part 60, appendix A–6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the

initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

* * * * *

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

* * * * *

(e) * * *

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

* * * * *

(f) * * *

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

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(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA–454/R–98–015 (incorporated by reference, see § 63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A–7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide

(SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you use an SO_2 CEMS, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to part 75 of this chapter.

(1) The SO_2 CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (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) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) 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.

■ 18. Section 63.7530 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (b) introductory text.
■ c. Redesignating paragraph (b)(3) as paragraph (b)(4) and adding new paragraph (b)(3).
■ d. Revising newly designated paragraph (b)(4).
■ e. Revising paragraph (c), (c)(2) through (4).
■ f. Adding paragraph (c)(5).
■ g. Revising paragraphs (d), (e), (g), and (h).
■ h. Adding paragraph (i).

The revisions and additions read as follows:

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2)(i). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

* * * * *

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \qquad \text{(Eq. 9)}$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and

pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (*e.g.,* when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1 \; , \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

Where:

X_1 = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, 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 (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30-\text{day} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{(Eq. 14)}$$

Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 720 operating hours.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (''back half'') of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run. (iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iii) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(iv) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(v) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(vii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(viii) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in § 63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

* * * * *

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 15)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard

deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} \left(Ci90 \times Qi \times 1.028 \right) \qquad \text{(Eq. 16)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} \left(Hgi90 \times Qi \right) \qquad \text{(Eq. 17)}$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} \left(TSM90i \times Qi \right) \qquad \text{(Eq. 18)}$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

* * * * *

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to item 5 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by

collecting the minimum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

■ 19. Section 63.7533 is amended by:
■ a. Revising the section heading.
■ b. Revising paragraph (a).
■ c. Revising paragraphs (b)(1) and (4).
■ d. Revising paragraphs (c) introductory text, (c)(1)(i) and (ii), (c)(2)(i), and (c)(3).
■ e. Revising paragraph (d) through (f).
■ f. Adding paragraph (g).

The revisions and addition read as follows:

§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html*.

(b) * * *

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

* * * * *

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) * * *

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

* * * * *

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual} \right) \div EI_{baseline} \qquad \text{(Eq. 19)}$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is operating, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

■ 20. Section 63.7535 is amended by revising the section heading and paragraphs (b), (c), and (d) to read as follows:

§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

* * * * *

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, 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 control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your annual report.

■ 21. Section 63.7540 is revised to read as follows:

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 12 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 12 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the

procedures in § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 13 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 13 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is operating.

(iii) Keep records of CO levels according to § 63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the 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). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of § 63.7530. If the results of recalculating the maximum TSM input using Equation 9 of § 63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 14 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 14 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, 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 (milliamps) on a 30-day rolling average basis, updated at the end of each new boiler or process heater operating hour.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) 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 test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) 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.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater 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.

(vii) 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.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart.

■ 22. Section 63.7541 is amended by revising paragraphs (a)(3) and (4) to read as follows:

§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

* * * * *

(a) * * *

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling

average parameter values consistent with the approved monitoring plan.

* * * * *

■ 23. Section 63.7545 is amended by:
■ a. Revising paragraphs (a) through (c).
■ b. Revising paragraphs (e) introductory text, (e)(1), (e)(2), (e)(3), (e)(4), (e)(5) introductory text, and (e)(5)(i).
■ c. Adding paragraph (e)(5)(ii).
■ d. Revising paragraphs (e)(8)(i) and (iii).
■ e. Revising paragraph (f) introductory text.
■ f. Revising paragraphs (g)(1) and (2).
■ g. Revising paragraphs (h) introductory text and (h)(1) and (3).
■ h. Removing paragraph (h)(4).

The revisions and addition read as follows:

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator 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 January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

* * * * *

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

* * * * *

(8) * * *

(i) "This facility complies with the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi)."

* * * * *

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

* * * * *

(g) * * *

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

* * * * *

(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

* * * * *

(3) The date upon which the fuel switch or physical change occurred.

■ 24. Section 63.7550 is revised to read as follows:

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission

limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or submitted 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 each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(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. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

(4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 12 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 13 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 14 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the 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 you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit or operating limit from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) [Reserved]

(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in § 63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk 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 Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.

(2) Within 60 days after the date of completing each CEMS performance evaluation test (defined in 63.2) you must submit the relative accuracy test audit (RATA) data to the EPA's Central Data Exchange by using CEDRI as mentioned in paragraph (h)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator.

(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.

■ 25. Section 63.7555 is amended by:

■ a. Revising paragraphs (d) introductory text and (d)(2) through (6).

■ b. Adding paragraphs (d)(9) through (11).

■ c. Revising paragraphs (f) through (h).

■ d. Adding paragraphs (i) and (j).

The revisions and additions read as follows:

§ 63.7555 What records must I keep?

* * * * *

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

* * * * *

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in § 241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 12 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 13 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(6) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), 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 relevant pollutant to increase within the past year.

* * * * *

(9) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 14 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(10) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(11) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

* * * * *

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

(i) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(j) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

■ 26. Section 63.7570 is amended by revising paragraph (a) and paragraph (b) introductory text to read as follows:

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator 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 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 (5) of this section are retained by the EPA 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.

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■ 27. Section 63.7575 is amended by:

■ a. Adding in alphabetical order definitions for "10-day rolling average," "30-day rolling average," "Annual capacity factor," "Average annual heat input rate," "Benchmark," "Biodiesel," "Daily block average," "Efficiency credit," "Energy management program," "Fluidized bed boiler with an integrated fluidized bed heat exchanger," "Heavy liquid," "Light liquid," " "Major source for oil and natural gas production facilities," "Minimum oxygen level," "Other combustor", "Oxygen analyzer system", "Oxygen trim system", "Pile burner", "Regulated gas stream", "Residential boiler," "Residual oil", "Secondary material," "Shutdown", "Sloped grate", "Startup", "Stoker/sloped grate/other unit designed to burn kiln dried biomass," Stoker/sloped grate/other unit designed to burn wet biomass," "Suspension burner," "Total selected metals (TSM)," "Traditional fuel," "Ultra low sulfur liquid fuel," "Unit designed to burn heavy liquid subcategory," "Unit designed to burn light liquid subcategory," and "Vegetable oil."

■ b. Revising the definitions for "Boiler," "Boiler system," "Coal," Commercial/institutional boiler," "Deviation," "Distillate oil," "Dry scrubber," "Dutch oven," "Electric utility steam generating unit," "Energy assessment," "Energy use system," "Equivalent," "Federally enforceable," "Fluidized bed boiler", "Fuel cell," "Fuel type," "Gaseous fuel," "Heat input," "Hot water heater," "Hybrid suspension grate boiler," "Industrial boiler," "Limited-use boiler or process heater," "Liquid fuel," "Load fraction," "Metal process furnaces," "Minimum activated carbon injection rate," "Minimum scrubber liquid flow rate," "Minimum sorbent injection rate," "Natural gas," "Other gas 1 fuel," "Period of natural gas curtailment or supply interruption," "Process heater," "Qualified energy assessor," "Residual oil," "Solid fossil fuel," "Steam output," "Stoker," "Temporary boiler," "Tune-up," "Unit designed to burn gas 1 subcategory," "Unit designed to burn gas 2 (other) subcategory," "Unit designed to burn liquid subcategory," "Unit designed to burn liquid fuel that is a non-continental unit," "Unit designed to burn solid fuel," "Waste heat boiler," "Waste heat process heater."

■ c. Removing the definitions for "Benchmarking," "Emission credit," "Liquid fuel subcategory," and "Suspension boiler."

The revisions read as follows:

§ 63.7575 What definitions apply to this subpart?

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10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

* * * * *

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

* * * * *

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

* * * * *

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

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Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

* * * * *

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

* * * * *

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

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 applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; 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.

* * * * *

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 § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751–11b (incorporated by reference, see § 60.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

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. To be ''capable of combusting'' fossil fuels, an EGU would need to have these fuels allowed in their operating permits 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 EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

* * * * *

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

* * * * *

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite

consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an ''as received'' basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

* * * * *

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, 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.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

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Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

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Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Light liquid includes distillate oil, biodiesel, or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5).

Major source for oil and natural gas production facilities, 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 vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

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Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

* * * * *

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

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Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

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Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

* * * * *

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller.

* * * * *

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

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Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

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Regulated gas stream means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396–10 (incorporated by reference, *see* § 63.14(b)).

* * * * *

Secondary material means the material as defined in § 241.2 of this chapter.

Shutdown means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

* * * * *

Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be calculated using Equations 21 through 25 of this section, as appropriate:

(i) For emission limits for boilers in the unit designed to burn solid fuel subcategory use Equation 21 of this section:

$$EL_{OBE} = EL_T \times 12.7 \text{ MMBtu/Mwh} \quad \text{(Eq. 21)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 22 of this section:

$$EL_{OBE} = EL_T \times 12.2 \text{ MMBtu/Mwh} \quad \text{(Eq. 22)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 23 of this section:

$$EL_{OBE} = EL_T \times 13.9 \text{ MMBtu/Mwh} \quad \text{(Eq. 23)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in one of the subcategories of units designed to burn liquid fuels use Equation 24 of this section:

$$EL_{OBE} = EL_T \times 13.8 \text{ MMBtu/Mwh} \quad \text{(Eq. 24)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the unit designed to burn gas 2 (other)

subcategory, use Equation 25 of this section:

$$EL_{OBE} = EL_T \times 10.4 \text{ MMBtu/Mwh} \quad \text{(Eq. 25)}$$

Where:
EL_{OBE} = Emission limit in units of pounds per megawatt-hour.
EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

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 under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler 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 boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. 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 within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in § 241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

* * * * *

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

* * * * *

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn

liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Vegetable oil means oils extracted from vegetation.

* * * * *

Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

* * * * *

■ 28. Table 1 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.28 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E–07 [a] lb per MMBtu of heat input.	8.7E–07 [a] lb per MMBtu of steam output or 1.1E–05 [a] lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel.	a. Filterable PM (or TSM)	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	1.1E–03 lb per MMBtu of steam output or 1.4E–02 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 2.9E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.2E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	5.8E–01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 3.7E–04 lb per MWh).	Collect a minimum of 2 dscm per run.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E–01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (4.2E–03 lb per MMBtu of steam output or 5.6E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	2.2E–01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E–04 [a] lb per MMBtu of steam output or 1.2E–03 [a] lb per MWh).	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	3.1E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (6.6E–03 lb per MMBtu of steam output or 9.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	3.5E–01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	4.3E–03 lb per MMBtu of steam output or 4.5E–02 lb per MWh; or (5.2E–05 lb per MMBtu of steam output or 5.5E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 [a] lb per MMBtu of heat input).	3.0E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (5.1E–05 lb per MMBtu of steam output or 4.1E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	3.3E–02 lb per MMBtu of steam output or 3.7E–01 lb per MWh; or (5.5E–04 lb per MMBtu of steam output or 6.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	4.4E–04 lb per MMBtu of heat input.	4.8E–04 lb per MMBtu of steam output or 6.1E–03 lb per MWh.	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input.	5.3E–07 [a] lb per MMBtu of steam output or 6.7E–06 [a] lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	1.5E–02 lb per MMBtu of steam output or 1.8E–01 lb per MWh; or (8.2E–05 lb per MMBtu of steam output or 1.1E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	1.2E–03 [a] lb per MMBtu of steam output or 1.6E–02 [a] lb per MWh; or (3.2E–05 lb per MMBtu of steam output or 4.0E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	2.5E–02 lb per MMBtu of steam output or 3.2E–01 lb per MWh; or (9.4E–04 lb per MMBtu of steam output or 1.2E–02 lb per MWh).	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	2.9E–03 lb per MMBtu of steam output or 1.8E–02 lb per MWh.	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	1.4E–05 lb per MMBtu of steam output or 8.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 7.0E–02 lb per MWh; or (3.5E–04 lb per MMBtu of steam output or 2.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before January 31, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

■ 29. Table 2 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.27 lb per MWh.	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	5.7E–06 lb per MMBtu of heat input.	6.4E–06 lb per MMBtu of steam output or 7.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM)	4.0E–02 lb per MMBtu of heat input; or (5.3E–05 lb per MMBtu of heat input).	4.2E–02 lb per MMBtu of steam output or 4.9E–01 lb per MWh; or (5.6E–05 lb per MMBtu of steam output or 6.5E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average.	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.3E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.7E–02 lb per MMBtu of heat input; or (2.4E–04 lb per MMBtu of heat input).	4.3E–02 lb per MMBtu of steam output or 5.2E–01 lb per MWh; or (2.8E–04 lb per MMBtu of steam output or 3.4E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E–01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E–01 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	3.7E–01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E–03 lb per MMBtu of steam output or 5.6E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	4.6E–01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E–01 lb per MMBtu of heat input; or (1.2E–03 lb per MMBtu of heat input).	1.4E–01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E–03 lb per MMBtu of steam output or 1.7E–02 lb per MWh).	Collect a minimum of 1 dscm per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
10. Suspension burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	5.2E–02 lb per MMBtu of steam output or 7.1E–01 lb per MWh; or (6.6E–03 lb per MMBtu of steam output or 9.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	8.4E–01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E–01 lb per MMBtu of heat input; or (2.0E–03 lb per MMBtu of heat input).	3.9E–01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E–03 lb per MMBtu of steam output or 2.8E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid.	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen.	2.4 lb per MMBtu of steam output or 12 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–02 lb per MMBtu of heat input; or (5.8E–03 lb per MMBtu of heat input).	5.5E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (1.6E–02 lb per MMBtu of steam output or 8.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	2,800 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	2.8 lb per MMBtu of steam output or 31 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E–01 lb per MMBtu of heat input; or (4.5E–04 lb per MMBtu of heat input).	5.5E–01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E–04 lb per MMBtu of steam output or 6.3E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	1.1E–03 lb per MMBtu of heat input.	1.4E–03 lb per MMBtu of steam output or 1.6E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E–06 lb per MMBtu of heat input.	2.5E–06 lb per MMBtu of steam output or 2.8E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [b] collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E–02 lb per MMBtu of heat input; or (2.0E–04 lb per MMBtu of heat input).	7.5E–02 lb per MMBtu of steam output or 8.6E–01 lb per MWh; or (2.5E–04 lb per MMBtu of steam output or 2.8E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E–03 lb per MMBtu of heat input; or (6.2E–05 lb per MMBtu of heat input).	9.6E–03 lb per MMBtu of steam output or 1.1E–01 lb per MWh; or (7.5E–05 lb per MMBtu of steam output or 8.6E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	2.7E–01 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	3.3E–01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E–03 lb per MMBtu of steam output or 1.2E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	2.9E–03 lb per MMBtu of steam output or 1.8E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	1.4E–05 lb per MMBtu of steam output or 8.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E–03 lb per MMBtu of heat input or (2.1E–04 lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 7.0E–02 lb per MWh; or (3.5E–04 lb per MMBtu of steam output or 2.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

■ 30. Table 3 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the following applicable work practice standards:

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater.	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units.	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575: a. A visual inspection of the boiler or process heater system.

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS—Continued

If your unit is . . .	You must meet the following . . .
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator. d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified. f. A list of cost-effective energy conservation measures that are within the facility's control. g. A list of the energy savings potential of the energy conservation measures identified. h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup.	You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas. If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose. You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown.	You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR. You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

■ 31. Table 4 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the applicable operating limits:

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control on a boiler not using a PM CPMS.	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS—Continued

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
2. Wet acid gas (HCl) scrubber control on a boiler not using a HCl CEMS.	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not using a PM CPMS.	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or
	b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on units not using a PM CPMS.	a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler not using a mercury CEMS.	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on units not using a PM CPMS.	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a).
10. SO_2 CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS, maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the most recent HCl performance test, as specified in Table 8.

■ 32. Table 5 to subpart DDDDD of part 63 is amended by:

■ a. Revising the entry for "1. Particulate matter."

■ b. Remove the entry for "5. Dioxins/Furans".

■ c. Redesignating the entries for "2. Hydrogen chloride," "3. Mercury," and "4. CO" as "3. Hydrogen chloride," "4. Mercury," and "5. CO," respectively.

■ d. Revising the newly redesignated entries for "4. Mercury" and "5. CO."

■ e. Add entry for "2. Total selected metals."

The revisions and addition read as follows:

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
1. Filterable PM	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A–3 or A–6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the TSM emission concentration ...	Method 29 at 40 CFR part 60, appendix A–8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
3. HCl	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the HCl emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A–8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the mercury emission concentration.	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine oxygen concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–3 of this chapter, or ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981.[a]
	c. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A–4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

* * * * *

■ 33. Table 6 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192[a], or ASTM D7430[a], or ASTM D6883[a], or ASTM D2234/D2234M[a](for coal) or EPA 1631 or EPA 1631E or ASTM D6323[a] (for solid), or EPA 821–R–01–013 (for liquid or solid), or ASTM D4177[a] (for liquid), or ASTM D4057[a] (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] (for biomass), or EPA 3050[a] (for solid fuel), or EPA 821–R–01–013[a] (for liquid or solid), or equivalent.

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS—Continued

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a], ASTM E871[a], or ASTM D5864[a], or ASTM D240, or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D6722[a] (for coal), EPA SW–846–7471B[a] (for solid samples), or EPA SW–846–7470A[a] (for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content.	Equation 8 in § 63.7530.
	h. Calculate the mercury emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 12 in § 63.7530.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192[a], or ASTM D7430[a], or ASTM D6883[a], or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M§[a] (for coal), or ASTM D5198§[a] (for biomass), or EPA 3050[a] or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), ASTM D5864, ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871[a], or D5864[a], or ASTM D240[a], or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels) or equivalent.
	f. Measure chlorine concentration in fuel sample.	EPA SW–846–9250[a], ASTM D6721[a], ASTM D4208[a] (for coal), or EPA SW–846–5050[a] or ASTM E776[a] (for solid fuel), or EPA SW–846–9056[a] or SW–846–9076[a] (for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content.	Equation 7 in § 63.7530.
	h. Calculate the HCl emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 11 in § 63.7530.
3. Mercury Fuel Specification for other gas 1 fuels.	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter.	Method 30B (M30B) at 40 CFR part 60, appendix A–8 of this chapter or ASTM D5954[a], ASTM D6350[a], ISO 6978–1:2003(E)[a], or ISO 6978–2:2003(E)[a], or EPA–1631[a] or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater.	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784[a] or equivalent.
4. TSM for solid fuels	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192[a], or ASTM D7430[a], or ASTM D6883[a], or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), or ASTM D4177[a],(for liquid fuels)or ASTM D4057[a] (for liquid fuels),or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] or TAPPI T266[a] (for biomass), or EPA 3050[a] or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871[a], or D5864, or ASTM D240[a], or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample	ASTM D3683[a], or ASTM D4606[a], or ASTM D6357[a] or EPA 200.8[a] or EPA SW–846–6020[a], or EPA SW–846–6020A[a], or EPA SW–846–6010C[a], EPA 7060[a] or EPA 7060A[a] (for arsenic only), or EPA SW–846–7740[a] (for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content.	Equation 9 in § 63.7530.
	h. Calculate the TSM emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 13 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

■ 34. Table 7 to subpart DDDDD of part 63 is amended by:

■ a. Revising the entry for ''1. Particulate matter or mercury,''.

■ b. Revising the entry for ''2. Hydrogen Chloride,''.

■ c. Revising the entry for ''3. Mercury,''.

■ d. Revising the entry for ''4. Carbon monoxide''.

The revisions read as follows:

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM, TSM, or mercury	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b).	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM or mercury performance test.	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. (b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b).	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test.	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. HCl	a. Wet scrubber operating parameters.	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b).	(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the HCl performance test.	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
	c. Alternative Maximum SO_2 emission rate.	i. Establish a site-specific maximum SO_2 emission rate operating limit according to § 63.7530(b).	(1) Data from SO_2 CEMS and the HCl performance test.	(a) You must collect the SO_2 emissions data according to § 63.7525(m) during the most recent HCl performance tests.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(b) The maximum SO_2 emission rate is equal to the lowest hourly average SO_2 emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b).	(1) Data from the activated carbon rate monitors and mercury performance test.	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (*e.g.,* actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520.	(1) Data from the oxygen analyzer system specified in § 63.7525(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
*	*	*	*	*	*	*

■ 35. Table 8 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE—Continued

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate.	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input.	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and b. Reduce the data to 12-month rolling averages; and c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(2). b. Reducing the data to 30-day rolling averages; and c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO_2 emissions using SO_2 CEMS	a. Collecting the SO_2 CEMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average SO_2 CEMS emission rate to a level at or below the minimum hourly SO_2 rate measured during the most recent HCl performance test according to § 63.7530.

■ 36. Table 9 to subpart DDDDD of part 63 is amended by revising the entry for ''1. Compliance report'' to read as follows:

As stated in § 63.7550, you must comply with the following requirements for reports:

TABLE 9 TO SUBPART DDDDD OF PART 63—REPORTING REQUIREMENTS

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).

* * * * * * *

■ 37. Table 10 to subpart DDDDD of part 63 is amended by:

■ a. Revising the entry for ''§ 63.6(i)''.

■ b. Revising the entry for ''§ 63.7(e)(1)''.

■ c. Revising the entry for ''63.8(g)''.

■ d. Revising the entry for ''§ 63.10(e) and (f)''.

■ e. Adding an entry for ''§ 63.10(e)''.

The revisions and addition read as follows.

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD

Citation	Subject	Applies to subpart DDDDD
*	* * *	* * *
§ 63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD—Continued

Citation	Subject	Applies to subpart DDDDD
*	* * *	* * *
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
*	* * *	* * *
§ 63.8(g)	Reduction of monitoring data	Yes.
*	* * *	* * *
§ 63.10(e)	Additional reporting requirements for sources with CMS.	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements.	Yes.
*	* * *	* * *

■ 38. Add Table 11 to subpart DDDDD of part 63 to read as follows:

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis.	a. Mercury	8.0E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis.	a. Mercury	2.0E–06 lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
4. Units designed to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
5. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
7. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run
12. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	8.0E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
14. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel ..	a. HCl	4.4E–04 lb per MMBtu of heat input ...	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
17. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run
19. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 4 dscm per run
20. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

■ 39. Add Table 12 to subpart DDDDD of part 63 to read as follows:

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E–06 [a] lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E–04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E–07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–03[a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

■ 40. Add Table 13 to subpart DDDDD of part 63 to read as follows:

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE JANUARY 31, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.8E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.8E–02 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–01 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE JANUARY 31, 2013—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
9. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	5.1E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.6E–02 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel ..	a. HCl	1.2E–03 lb per MMBtu of heat input ...	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
14. Units designed to burn heavy liquid fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–03 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
15. Units designed to burn light liquid fuel.	a. CO (or CEMS)	130 [a] ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, 1-day block average)..	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average).	1 hr minimum sampling time.

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE JANUARY 31, 2013—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

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Part II

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40 CFR Part 63

National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2006–0790; FRL–9698–5]

RIN 2060–AR14

National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; notice of final action on reconsideration.

SUMMARY: In this action, the EPA is taking final action on reconsideration of certain issues related to the emission standards to control hazardous air pollutants from new and existing industrial, commercial and institutional boilers at area sources which were issued under section 112 of the Clean Air Act. As part of this action, the EPA is amending certain compliance dates for the standard and making technical corrections to the final rule to clarify definitions, references, applicability and compliance issues raised by petitioners and other stakeholders affected by the rule. The EPA today is taking final action on the proposed reconsideration.

DATES: This final rule is effective on February 1, 2013. The incorporation by reference of certain publications listed in this final rule were approved by the Director of the Federal Register as of February 1, 2013.

ADDRESSES: The EPA established a single docket under Docket ID No. EPA–HQ–OAR–2006–0790 for this action. 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 Air Docket is (202) 566–1741.

FOR FURTHER INFORMATION CONTACT: Ms. Mary Johnson, Energy Strategies Group (D243–01), Sector Policies and Programs Division, Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5025; fax number: (919) 541–5450; email address: *johnson.mary@epa.gov.*

Executive Summary

Purpose of This Regulatory Action

The EPA is taking final action on its proposed reconsideration of certain provisions of its March 21, 2011, final rule that established emission standards for the source category of new and existing industrial, commercial, and institutional boilers located at area source facilities listed pursuant to CAA sections 112(c)(3), 112(c)(6), and 112(k)(3)(B).

Section 112(d) of the CAA requires the EPA to regulate HAP from both major and area stationary sources. Section 112(d)(5) of the CAA allows the EPA to establish standards for area sources of HAP "which provide for the use of generally available control technologies (GACT) or management practices by such sources to reduce emissions of hazardous air pollutants." While GACT serves as the basis for standards of most emissions from area source boilers, two pollutants emitted by coal-fired boilers, POM as 7–PAH and Hg, must be regulated based on the performance of MACT. These two pollutants are regulated based on MACT because area source industrial, commercial and institutional boilers combusting coal were listed under section 112(c)(6) of the CAA due to the source categories' emissions of POM and Hg. Section 112(c)(6) requires the EPA to regulate sources listed pursuant to that provision by issuing standards under section 112(d)(2) or (d)(4). The final rule meets this requirement by setting MACT standards for Hg and CO (as a surrogate for POM) for units in the coal-fired subcategory. Further, the final rule sets standards based on GACT for the urban HAP, other than Hg and POM, emitted from coal-fired boilers that pose the greatest public health risk, pursuant to section 112(c)(3) of the CAA, including arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, ethylene dioxide, and PCBs. In addition, the final rule sets standards based on GACT for boilers combusting oil or biomass for urban HAP, including Hg, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, POM, ethylene dioxide, and PCBs.

In developing the MACT standards for coal-fired boilers, the EPA considered section 112(h) of the CAA, which allows the EPA to establish work practice standards in lieu of numerical emission limits under section 112(d)(2) only in cases where the agency determines that it is not feasible to prescribe or enforce an emission standard. The EPA has set work practice standards for emissions of Hg and POM from small coal-fired boilers, pursuant to section 112(h), in the form of periodic tune-ups.

This final rule amends certain provisions of the final rule issued by EPA on March 11, 2011, and responds to petitions for reconsideration filed by a number of different entities.

Summary of Major Reconsideration Provisions

In general, the final rule requires facilities classified as area sources of HAP with affected boilers to reduce emissions of harmful toxic air emissions from these combustion sources, improving air quality, and protecting public health in communities where these facilities are located.

Recognizing the diversity of this source category and the multiple sectors of the economy this rule affects, the EPA is establishing seven subcategories for boilers based on the design of the combustion equipment and operating schedules of the unit. In addition to the coal, biomass, and oil subcategories in the March 2011 final rule, we are establishing subcategories for seasonal boilers, limited-use boilers, oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr, and certain boilers that use a continuous oxygen trim system.

Numerical emission limits, based on MACT, are established for Hg and CO at new and existing large coal-fired boilers (i.e., with a design heat input capacity of 10 MMBtu/hr or more). A review of the data has resulted in changes to the Hg and CO emission limits contained in the March 2011 final rule. The EPA is also establishing a CEMS alternative compliance option for the numeric CO emission limit. Coal-fired boilers subject to a CO emission limit can comply with the limit using a periodic stack test and CPMS, or by using CEMS. The CO CEMS alternative compliance option is based on a 10-day rolling average and provides additional compliance flexibility to sources with existing CO CEMS equipment. New and existing small coal-fired units (*i.e.,* with a design heat input capacity of less than 10 MMBtu/hr) are subject to periodic tune-up work practices for CO and Hg in lieu of numeric emission limits because the EPA found that it was technologically

and economically impracticable to apply measurement methodology to these small sources, pursuant to CAA section 112(h).

Numerical emission limits, based on GACT, are established for PM as a surrogate for urban metal HAP other than Hg for new large coal-fired boilers. New and existing small coal-fired boilers are subject to periodic tune-up management practices for PM as a surrogate for urban metal HAP other than Hg, and for CO as a surrogate for urban organic HAP other than POM, based on GACT.

New large biomass- and oil-fired boilers are subject to numerical emission limits for PM as a surrogate for urban metal HAP, based on GACT. Existing biomass and oil-fired boilers and new small biomass- and oil-fired boilers are subject to periodic tune-up management practices for PM as a surrogate for urban metal HAP, based on GACT. New and existing biomass- and oil-fired boilers are subject to periodic tune-up management practices for CO as a surrogate for urban organic HAP, based on GACT. Certain other subcategories (seasonal boilers, limited-use boilers, oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr, and boilers with an oxygen trim system) are subject to periodic tune-up work practice or management practice requirements tailored to their schedule of operation and types of fuel.

The compliance date for existing sources is March 21, 2014. The compliance date for new sources that began operations on or before May 20, 2011 is May 20, 2011. For new sources that start up after May 20, 2011, the compliance date is the date of startup. New sources are defined as sources that began operation after June 4, 2010.

Costs and Benefits

This final action is intended to clarify definitions, references, applicability and compliance issues, but not change the coverage of the final rule. The final rule will affect an estimated 180,000 existing area source boilers and the EPA projects that approximately an additional 6,800 new boilers will be subject to the rule over the initial 3-year period. The clarifications should make it easier for owners and operators and for local and state authorities to understand and implement the rule's requirements. As compared to the March 2011 final rule, this final rule will not affect the estimated emission reductions, control costs or the benefits of the rule in substance. This final rule does not impose any additional regulatory requirements beyond those imposed by the previously promulgated boiler area source rule and, in fact, will result in a decrease in regulatory requirements for certain subcategories of boilers. A more detailed discussion of the costs and benefits of the March 2011 final rule is provided at 76 FR 15579, March 21, 2011, and 76 FR 80542, December 23, 2011. Section VI of this preamble provides a discussion of the impacts of this final rule.

SUPPLEMENTARY INFORMATION:

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

7–PAH 7-polynuclear aromatic hydrocarbons
ACI activated carbon injection
ASTM American Society for Testing and Materials
Btu British thermal unit
CO carbon monoxide
CEMS continuous emission monitoring system
CDX Central Data Exchange
CAA Clean Air Act
CFR Code of Federal Regulations
COMS continuous opacity monitoring system
CPMS continuous parameter monitoring system
DOE Department of Energy
ERT Electronic Reporting Tool
ESP electrostatic precipitator
FR Federal Register
GACT generally available control technologies
HAP hazardous air pollutants
Hg mercury
HQ Headquarters
ISO International Standards Organization
lb pounds
MACT maximum achievable control technology
MMBtu million British thermal units
NAA No Action Assurance
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NSPS new source performance standard
NTTAA National Technology Transfer and Advancement Act
OMB Office of Management and Budget
PCBs polychlorinated biphenyls
PM particulate matter
POM polycyclic organic matter
ppm parts per million
PSD prevention of significant deterioration
RFA Regulatory Flexibility Act
RIN Regulatory Information Number
TBtu trillion British thermal units
TTN Technology Transfer Network
tpy tons per year
UMRA Unfunded Mandates Reform Act of 1995
UPL upper prediction limit
VCS Voluntary Consensus Standards
WWW Worldwide Web

Organization of This Document. The information presented in this preamble is organized as follows:

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K. Congressional Review Act

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by this action include:

Industry category	NAICS Code [a]	Examples of regulated entities
Any area source facility using a boiler as defined in the final rule.	321	Wood product manufacturing.
	11	Agriculture, greenhouses.
	311	Food manufacturing.
	327	Nonmetallic mineral product manufacturing.
	424	Wholesale trade, nondurable goods.
	531	Real estate.
	611	Educational services.
	813	Religious, civic, professional, and similar organizations.
	92	Public administration.
	722	Food services and drinking places.
	62	Health care and social assistance.
	22111	Electric power generation.

[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 regulated by this final action. To determine whether your facility may be affected by this action, you should examine the applicability criteria in 40 CFR 63.11193 of subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources). If you have any questions regarding the applicability of this final rule to a particular entity, consult either the air permit authority for the entity or your EPA regional representative, as listed in 40 CFR 63.13 of subpart A (General Provisions).

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

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

C. Judicial Review

Under the CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 2, 2013. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review.

Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

II. Background Information

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

On March 21, 2011 (76 FR 15554), the EPA issued the NESHAP for industrial, commercial and institutional area source boilers pursuant to CAA sections 112(c)(3), 112(c)(6), and 112(k)(3)(B).

CAA section 112(k)(3)(B) directs the EPA to identify at least 30 HAP that, as a result of emissions from area sources, pose the greatest threat to public health in the largest number of urban areas. The EPA implemented this provision in 1999 in the Integrated Urban Air Toxics Strategy, (64 FR 38715, July 19, 1999) (Strategy). Specifically, in the Strategy, the 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 the 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. Under CAA section 112(d)(5), the EPA may elect to promulgate standards or requirements for area sources "which provide for the use of generally available control technologies ("GACT") or management practices by such sources to reduce emissions of hazardous air pollutants."

CAA section 112(c)(6) requires that the EPA list categories and subcategories of sources assuring that sources accounting for not less than 90 percent of the aggregate emissions of each of seven specified HAP are subject to standards under CAA sections 112(d)(2) or (d)(4), which require the application of the more stringent MACT. The seven HAP specified in CAA section 112(c)(6) are as follows: Alkylated lead compounds, POM, hexachlorobenzene, Hg, PCBs, 2,3,7,8-tetrachlorodibenzofuran, and 2,3,7,8-tetrachlorodibenzo-p-dioxin.

As noted in the preamble to the final rule, (76 FR 15556, March 21, 2011), we listed area source industrial boilers and commercial/institutional boilers combusting coal under CAA section 112(c)(6) based on the source categories' contribution of Hg and POM, and under CAA section 112(c)(3) for their contribution of arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, ethylene dioxide, and PCBs, as well as Hg and POM. We promulgated final standards for coal-fired area source boilers to reflect the application of MACT for Hg and POM, and to reflect GACT for the urban HAP other than Hg and POM.

We listed industrial and commercial/institutional boilers combusting oil or biomass under CAA section 112(c)(3) for their contribution of Hg, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, POM, ethylene dioxide, and PCBs. For boilers firing oil or biomass, the final standards reflect GACT for all of the urban HAP.

On March 21, 2011, we also published a notice to initiate the reconsideration of certain aspects of the final rule for area source industrial, commercial and institutional boilers (76 FR 15266). The reconsideration notice identified several provisions of the final rule where additional public comment was appropriate. The notice also identified several issues of central relevance to the rulemaking where reconsideration was appropriate under CAA section 307(d).

Following promulgation of the final rule, the EPA also received petitions for reconsideration from the following organizations (Petitioners): American

Sugar Cane League of the U.S.A., Alaska Oil and Gas Association, American Coke and Coal Chemicals Institute, American Iron and Steel Institute, American Petroleum Institute, Council of Industrial Boiler Owners, Industry Coalition (American Forest and Paper Association (AF&PA) et. al.), National Petrochemical and Refiners Association, Sierra Club, and the State of Washington Department of Ecology. Petitioners, pursuant to CAA section 307(d)(7)(B), requested that the EPA reconsider numerous provisions in the rules. On December 23, 2011, the EPA granted the petitions for reconsideration on certain issues, and proposed certain revisions to the final rule in response to the reconsideration petitions and to address the issues that the EPA previously identified as warranting reconsideration. That proposal solicited comment on several specific aspects of the rule, including:

- Establishing separate requirements for seasonally operated boilers.
- Addressing temporary boilers.
- Clarifying the initial compliance schedule for existing boilers subject to tune-ups.
- Defining periods of gas curtailment.
- Providing an optional CO compliance mechanism using CEMS.
- Averaging times for parameter monitoring.
- Providing an affirmative defense for malfunction events.
- Adjusting frequency of tune-up work practices for very small units.
- Selecting a 99 percent confidence interval for setting the CO emission limit.
- Establishing GACT-based limits for biomass and oil-fired boilers.
- Scope and duration of the energy assessment and deadline for completing the assessment.
- Revising GACT-based limits for PM at new oil-fired boilers.
- Exempting area sources from title V permitting requirements.

In this action, the EPA is finalizing multiple changes to this NESHAP after considering public comments on the items under reconsideration.

III. Summary of Final Action on Reconsideration

As stated above, the December 23, 2011, proposed rule addressed specific issues and provisions the EPA identified for reconsideration. This summary reflects the agency's final action in regards to those provisions identified for reconsideration and on other discrete matters identified in response to comments or data received during the comment period.

A. Affected Sources

This final rule amends 40 CFR 63.11194 to specify that an existing dual-fuel fired boiler (*i.e.,* commenced construction or reconstruction on or before June 4, 2010) meeting the definition of gas-fired boiler, as defined in 40 CFR 63.11237, that meets the applicability requirements of subpart JJJJJJ after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel. A new or reconstructed dual-fuel fired boiler (*i.e.,* commenced construction or reconstruction after June 4, 2010) meeting the definition of gas-fired boiler, as defined in 40 CFR 63.11237, that meets the applicability criteria of subpart JJJJJJ after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be a new source under this subpart.

B. Source Category Exclusions

This final rule amends the list of boilers that are not part of the source categories subject to subpart JJJJJJ. We are revising this list (as set forth in 40 CFR 63.11195) to clarify certain boiler types and to include certain additional boilers that may be located at an industrial, commercial or institutional area source facility. These revisions of the source categories are described below.

1. Electric Boilers

The EPA is amending 40 CFR 63.11195 by adding electric boilers to the list of boilers not subject to subpart JJJJJJ. Electric boilers are defined in 40 CFR 63.11237 as follows:

> *Electric boiler* means a boiler in which electric heating serves as the source of heat. Electric boilers that burn gaseous or liquid fuel during periods of electrical power curtailment or failure are included in this definition.

2. Residential Boilers

The EPA is amending 40 CFR 63.11195 by adding residential boilers to the list of boilers not subject to subpart JJJJJJ. We are clarifying that a residential boiler may be part of a residential combined heat and power system and that a boiler serving a single unit residence dwelling that has since been converted or subdivided into condominiums or apartments may also be considered a residential boiler. Residential boilers are defined in 40 CFR 63.11237 as follows:

> *Residential boiler* means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (*e.g.,* university campus, military base, church grounds) or commercial/industrial facility (*e.g.,* farm) used primarily to provide heat and/or hot water for:
>
> (1) A dwelling containing four or fewer families, or
>
> (2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

3. Temporary Boilers

The EPA is amending 40 CFR 63.11195 by adding temporary boilers to the list of boilers not subject to subpart JJJJJJ. Similar to residential boilers, we did not intend to regulate temporary boilers under the area source standards because they are not part of either the industrial boiler source category or the commercial/institutional boiler source category. We note that neither the CAA section 112(c)(6) inventory nor the CAA section 112(c)(3) inventory included temporary boilers. In this final action, the EPA is simply clarifying the scope of categories regulated by subpart JJJJJJ. By their nature of being temporary, these boilers are operating in place of another non-temporary boiler while that boiler is being constructed, replaced or repaired, in which case we would have counted the non-temporary boiler as one being regulated. Additionally, the final major source rule for boilers excludes temporary boilers.

The definition of ''temporary boiler'' specifies that a boiler is not a temporary boiler if it remains at a location within the facility and performs the same or similar function for more than 12 consecutive months unless the regulatory agency approves an extension. The definition of ''temporary boiler'' also specifies that any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more. Temporary boilers are defined in 40 CFR 63.11237 as follows:

> *Temporary boiler* means any gaseous or liquid fuel boiler 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 boiler is not a temporary boiler if any one of the following conditions exists:
>
> (1) The equipment is attached to a foundation.
>
> (2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulatory agency

upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.

(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 within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

4. Boilers With Section 3005 Permits

The EPA is clarifying the language in 40 CFR 63.11195(c) to provide an exclusion stating ''unless such units do not combust hazardous waste and combust comparable fuels'' such that it reads: ''A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (*e.g.,* hazardous waste boilers), unless such units do not combust hazardous waste and combust comparable fuels.''

5. Boilers Used as Control Devices

The EPA is amending the language in 40 CFR 63.11195(g) to clarify that any boiler that is used as a control device to comply with a subpart under part 60, 61, or 65 of chapter 40 is not subject to subpart JJJJJJ provided that at least 50 percent of the heat input to the boiler is provided by the gas stream that is regulated under another subpart.

C. Emission Limits

1. Hg Emission Limit for Coal-Fired Boilers

The EPA is amending the Hg emission limit for large coal-fired boilers to 0.000022 lb per MMBtu based on a revised analysis. The revised analysis excludes data for a utility boiler that were erroneously used as the basis for the Hg emission limit included in the March 2011 final rule. Further discussion of this revision to the Hg emission limit is located in the December 23, 2011, proposal (76 FR 80541).

A memorandum ''*Beyond-the-Floor Analysis for Mercury and Carbon Monoxide*'' located in the docket for the rulemaking describes our beyond-the-floor analysis for Hg and CO emissions from new and existing area source coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater. In the beyond-the-floor option for Hg emissions, new and existing coal-fired boilers would be required to comply with a Hg emission limit more stringent than the MACT floor-based emission limit of 2.2×10^{-5} lb of Hg per MMBtu. To comply with a limit more stringent than the fabric filter-based MACT floor limit, it is expected that an affected boiler would need to employ fabric filter control along with ACI. In summary, we determined that the beyond-the-floor option of installing ACI for Hg control from area source coal-fired boilers is not economically feasible.

As discussed in the preamble to the June 2010 proposed rule (75 FR 31896) and the preamble to the March 2011 final rule (76 FR 15554), we also considered whether fuel switching was an appropriate control technology for purposes of determining either the MACT floor level or beyond-the-floor level of control. We determined that fuel switching was not an appropriate floor or beyond-the-floor control. As also discussed in the June 2010 and March 2011 preambles, we determined that an energy assessment requirement was an appropriate beyond-the-floor option for existing large boilers. These previous analyses continue to be applicable for mercury.

2. Using the UPL for Setting the CO Emission Limit

The EPA is amending the CO emission limit for coal-fired boilers to reflect a revised analysis that uses the 99 percent confidence level in determining the UPL. Based on the results of the revised analysis, we are amending the CO emission limit for new and existing coal-fired boilers from 400 ppm by volume on a dry basis, corrected to 3 percent oxygen, to 420 ppm by volume on a dry basis, corrected to 3 percent oxygen.

As discussed in the ''*Beyond-the-Floor Analysis for Mercury and Carbon Monoxide*'' memorandum, to comply with a limit more stringent than the MACT floor based CO limit, it is expected that new and existing area source coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater may need to install an oxidation catalyst. As fully explained in the memorandum, we determined that the beyond-the-floor option of installing an oxidation catalyst for CO control was technically infeasible. Other methods of reducing CO emissions, such as upgrading new burners and overfire air systems, were also considered and determined to be technically infeasible options. As explained earlier in this preamble, we determined that fuel switching was not an appropriate floor or beyond-the-floor control and that an energy assessment requirement was an appropriate beyond-the-floor option for existing large boilers. These previous analyses continue to be applicable for CO.

3. Compliance Alternative for PM for Certain Oil-Fired Boilers

The EPA is amending the applicability of PM emission limit requirements for certain new or reconstructed oil-fired boilers. We are amending 40 CFR 63.11210 to specify that new or reconstructed oil-fired boilers satisfy GACT for PM when they combust 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 emission limit under this subpart and do not use a post-combustion technology (except a wet scrubber) to reduce PM or sulfur dioxide emissions.

D. Tune-Up Work Practice and Management Practice Standards

1. Requirements for Seasonally Operated Boilers

The EPA is establishing separate requirements for a subcategory of boilers that are seasonally operated. For seasonally operated boilers, we are amending 40 CFR 63.11223 to specify that these boilers are required to complete a tune-up every 5 years, instead of on a biennial basis as is required for most non-seasonal boilers. Specifically, existing seasonal boilers are required to complete the initial tune-up by March 21, 2014, and a subsequent tune-up every 5 years after the initial tune-up. New and reconstructed seasonal boilers are not required to complete an initial tune-up, but are required to complete a tune-up every 5 years after the initial startup of the new or reconstructed boiler.[1] A combined total of 15 days of periodic testing of the seasonal boiler during the 7-month shutdown is allowed. The definition of ''seasonal boiler'' clarifies that it only applies to biomass- or oil-fired boilers. Seasonally operated boilers are defined in 40 CFR 63.11237 as follows:

Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to

[1] Generally, boilers are initially installed optimized for efficiency, *i.e.,* ''in tune.'' Periodic tune-ups restore a boiler to its efficient state, given its age and other parameters. We do not require a tune-up upon startup because boilers normally would already be efficient at that time. Emission reductions are projected to occur by maintaining efficient combustion through periodic tune-ups.

boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

2. Requirements for Small Oil-Fired Units

The EPA is establishing separate requirements for a subcategory of oil-fired boilers with a heat input capacity of equal to or less than 5 MMBtu/hr. We are amending 40 CFR 63.11223 to specify that this subcategory of small oil-fired boilers are required to complete a tune-up every 5 years, instead of on a biennial basis as is required for most larger oil-fired boilers. Specifically, existing oil-fired boilers with a heat input capacity of equal to or less than 5 MMBtu/hr are required to complete the initial tune-up by March 21, 2014, and a subsequent tune-up every 5 years after the initial tune-up. New and reconstructed oil-fired boilers with a heat input capacity of equal to or less than 5 MMBtu/hr are not required to complete an initial tune-up, but are required to complete a tune-up every 5 years after the initial startup of the new or reconstructed boiler.

3. Requirements for Boilers With Oxygen Trim Systems

The EPA is establishing separate requirements for boilers with oxygen trim systems that maintain an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up. We are amending 40 CFR 63.11223 to specify that this subcategory of boilers is required to complete a tune-up every 5 years. Specifically, existing boilers with oxygen trim systems are required to complete the initial tune-up by March 21, 2014, and a subsequent tune-up every 5 years after the initial tune-up. New and reconstructed boilers with oxygen trim systems are not required to complete an initial tune-up, but are required to complete a tune-up every 5 years after the initial startup of the new or reconstructed boiler.

4. Requirements for Limited-Use Boilers

The EPA is establishing separate requirements for a subcategory of boilers that operate on a limited basis. The limited-use subcategory includes any boiler that burns any amount of solid or liquid fuels and has a federally enforceable average annual capacity factor of no more than 10 percent. For limited-use boilers, we are amending 40 CFR 63.11223 of the final rule to specify that these boilers are required to complete a tune-up every 5 years. Specifically, existing limited-use boilers are required to complete the initial tune-up by March 21, 2014, and a subsequent tune-up every 5 years after the initial tune-up. New and reconstructed limited-use boilers are not required to complete an initial tune-up, but are required to complete a tune-up every 5 years after the initial startup of the new or reconstructed boiler. Limited-use boilers are not subject to the emission limits in Table 1 to the subpart, the energy assessment requirements in Table 2 to the subpart, or the operating limits in Table 4 to the subpart.

E. Energy Assessment Work Practice and Management Practice Standards

1. Scope

The EPA is amending the definition of ''energy assessment'' to clarify that the scope of the energy assessment does not encompass energy use systems located off-site or energy use systems using electricity purchased from an off-site source. The energy assessment is limited to only those energy use systems, located on-site, associated with the affected boilers. We are also clarifying that the scope of the assessment is based on energy use by discrete segments of a facility (*e.g.*, production area or building) and not by a total aggregation of all individual energy using segments of a facility.

The definition of ''boiler system'' is being revised in this final rule to clarify that it means the boiler and associated components directly connected to and serving the energy use systems. We are amending the definition of ''energy use system'' to clarify that energy use systems are only those systems using energy clearly produced by affected boilers.

We are clarifying that energy assessor approval and qualification requirements are waived in instances where an energy assessment completed on or after January 1, 2008 meets or is amended to meet the energy assessment requirements in this final rule by March 21, 2014. Finally, we are specifying that a source that is operating under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected boilers, by March 21, 2014, satisfies the energy assessment requirement. We consider these energy management programs to be equivalent to the one-time energy assessment because facilities having these programs operate under a set of practices and procedures designed to manage energy use on an ongoing basis. These programs contain energy performance measurements and tracking plans with periodic reviews.

2. Compliance Date

As specified in 40 CFR 63.11196(a)(3), existing boilers that are subject to the energy assessment requirement must achieve compliance with the energy assessment requirement no later than March 21, 2014. Thus, in order to meet the requirements of the rule, energy assessments must, therefore, be completed by the compliance date (March 21, 2014) for existing sources.

3. Maximum Duration Requirements

The EPA is amending the definition of ''energy assessment'' for facilities with affected boilers with less than 0.3 TBtu/yr heat input capacity and for facilities with affected boilers with 0.3 to 1 TBtu/yr heat input capacity to change the maximum time to conduct the energy assessment from one day to 8 on-site technical hours and from three days to 24 on-site technical hours, respectively, and to allow sources to perform longer assessments at their discretion. We are also amending the definition of ''energy assessment'' for facilities with affected boilers with greater than 1 TBtu/yr heat input capacity to specify that the maximum time to conduct the assessment is up to 24 on-site technical hours for the first TBtu/yr plus 8 on-site technical hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator.

F. GACT-Based Standards

1. Establishing GACT-Based Emission Limits for Biomass- and Oil-Fired Boilers

The EPA is not amending the GACT-based standards, as specified in the March 21, 2011, final rule, for biomass- and oil-fired boilers. Specifically, the final standards for biomass- and oil-fired area source boilers are based on GACT instead of MACT as were the proposed standards for all pollutants except POM. Our rationale for the changes between proposal and promulgation for the biomass- and oil-fired boilers, including not requiring MACT for POM, can be found in the preamble to the promulgated area source standards (76 FR 15565–15567 and 15574–15575, March 21, 2011). The final standards for area source biomass- and oil-fired boilers require these boilers to meet the following standards:

New boilers with heat input capacity greater than 10 MMBtu/hr that are biomass-fired or oil-fired must meet GACT-based numerical emission limits for PM.

New boilers with heat input capacity greater than 10 MMBtu/hr that are biomass-fired or oil-fired must comply

with work practice standards to minimize the boiler's startup and shutdown periods following the manufacturer's recommendations, or the manufacturer's recommendations for a unit of similar design.

Existing boilers with heat input capacity greater than 10 MMBtu/hr that are biomass-fired or oil-fired must have a one-time energy assessment performed by a qualified energy assessor, an energy assessment completed on or after January 1, 2008 that meets or is amended to meet the energy assessment requirements in this final rule by March 21, 2014, or an energy management program established through energy management systems compatible with ISO 50001, that includes the affected boilers, by March 21, 2014, under which the owner or operator currently operates.

All new and existing units, regardless of size, that are biomass-fired or oil-fired must have a GACT-based periodic tune-up.

2. Setting GACT-Based PM Standards for New Oil-Fired Boilers

The EPA is not making any changes to the PM limit for new oil-fired boilers. New oil-fired boilers with heat input capacity greater than 10 MMBtu/hr must meet a GACT-based numerical emission limit for PM (0.03 lb per MMBtu of heat input). New oil-fired units, regardless of size, must have a GACT-based periodic tune-up. Our rationale for finalizing GACT-based PM emissions limits can be found in the preamble to the promulgated area source standards (76 FR 15574, March 21, 2011).

G. Initial Compliance

1. Dates

Some commenters have argued that the 3-year compliance deadline of March 21, 2014, for existing sources to meet the standards does not provide sufficient time for sources to meet the standards in view of the large number of sources subject to the rule and that these sources will be competing for the needed resources and materials from engineering consultants, permitting authorities, equipment vendors, construction contractors, financial institutions, and other critical suppliers.

As an initial matter, we note that many sources subject to the standards should be able to meet the standards within 3 years (*i.e.,* by March 21, 2014), even those that need to install pollution control technologies to do so. In addition, many sources subject to the standards are existing biomass- or oil-fired boilers or small coal-fired boilers (less than 10 MMBtu/hr) and will not need to install controls in order to demonstrate compliance, as these sources are subject only to work practices or management practices.

At the same time, the CAA allows title V permitting authorities to grant sources, on a case-by-case basis, extensions to the compliance time of up to 1 year if such time is needed for the installation of controls. *See* CAA section 112(i)(3)(B)). Permitting authorities are already familiar with, and in many cases have experience with, applying the 1-year extension authority under section 112(i)(3)(B) since the provision applies to all NESHAP. *See* 40 CFR 63.6(i)(4)(A). We believe that should the range of circumstances that commenters have cited as impeding sources' ability to install controls within 3 years materialize, then permitting authorities can take those circumstances into consideration when evaluating an existing source's request for a 1-year extension, and where such applications prove to be well-founded, permitting authorities can make the 1-year extension available to applicants.

In making a determination as to whether an extension is appropriate, we believe it is reasonable for permitting authorities to consider the large number of pollution control retrofit projects being undertaken for purposes of complying either with the standards in this rule or with those of other rules such as the Major Source Boilers Standards and the Mercury and Air Toxics Standards for the power sector that may be competing for similar resources.

Further, commenters have pointed out that in some cases operators of existing sources that are subject to these standards and that generate energy may opt to meet the standards by terminating operations at these sources and building new sources to replace the energy generation at the shut-down sources. While the ultimate discretion to provide a 1-year extension lies with the permitting authority, the EPA believes that it may be reasonable for permitting authorities to allow the fourth year extension for the installation of replacement sources of energy generation at the site of a facility applying for an extension for that purpose. Specifically, the EPA believes where an applicant demonstrates that it is building replacement sources of energy generation for purposes of meeting the requirements of these standards, such a replacement project could be deemed to constitute the ''installation of controls'' under section 112(i)(3)(B).

In sum, the EPA believes that although most, if not all, units will be able to fully comply with the standards 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.

2. Demonstrating Initial Compliance

The EPA is amending 40 CFR 63.11210 to clarify the dates by which new and reconstructed boilers need to demonstrate initial compliance. We are amending 40 CFR 63.11210(d) to clarify that only boilers that are subject to emission limits for PM, Hg or CO in Table 1 to subpart JJJJJJ have a 180-day period after the applicable compliance date to demonstrate initial compliance.

We are adding a new paragraph (i) to 40 CFR 63.11210 to clarify the initial compliance requirements for boilers located at existing major sources of HAP that become area sources on a timely basis. Any such existing boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2014 or upon the existing major source commencing operation as an area source. Any new or reconstructed boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2011 or startup. Notification of such changes must be submitted according to 40 CFR 63.11225(g).

We are adding a new paragraph (j) to 40 CFR 63.11210 that specifies initial compliance demonstration requirements for existing affected boilers that have not operated between the effective date of the rule and the source's compliance date. Owners and operators of boilers subject to emission limits must complete the initial compliance demonstration no later than 180 days after the re-start of the affected boiler, sources subject to tune-up requirements must complete the initial performance tune-up no later than 30 days after the re-start of the affected boiler, and sources subject to the one-time energy assessment must complete the assessment no later than the compliance date specified in 40 CFR 63.11196.

3. Schedule for Existing Boilers Subject to Tune-Up Requirements

The EPA is amending 40 CFR 63.11196 to specify that all existing boilers subject to the tune-up requirement have 3 years (by March 21, 2014) in which to demonstrate initial compliance, instead of 1 year as specified in the 2011 final rule (76 FR 15554, March 21, 2011) or 2 years as specified in the proposed reconsideration of final rule action (76

FR 80532, December 23, 2011). In the December 23, 2011, proposal, we specifically requested comment on whether the initial compliance period for the tune-up requirement should be extended to March 21, 2014.

4. Conducting Initial Tune-Ups at New and Reconstructed Sources

The EPA is removing the requirement for an initial tune-up for new and reconstructed boilers. Thus, new and reconstructed units are required to complete the applicable biennial or 5-year tune-up no later than 25 months or 61 months, respectively, after the initial startup of the new or reconstructed boiler.

5. Fuel Requirements

The EPA is amending 40 CFR 63.11223(a) to specify that boiler tune-ups must be conducted while burning the type of fuel that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.

H. Operating Limits

1. Operating Limits for Oxygen Concentration

The EPA is clarifying that the oxygen concentration must be at or above the minimum established during a performance stack test. These limits have also been clarified to be applicable when the unit is firing the fuel or fuel mixture utilized during the CO performance test.

2. Maximum Operating Load

The EPA is including provisions for establishing a unit-specific limit for maximum operating load that applies to any boiler subject to an emission limit for which compliance is demonstrated by a performance stack test. Operating load data includes fuel feed rate data or steam generation rate data.

3. Establishing Operating Limits for Wet Scrubbers

The EPA is amending the operating limit provisions in 40 CFR 63.11211(b)(2) for an ESP operated with a wet scrubber to remove the statement that the operating limits for ESP do not apply to dry ESP systems operated without a wet scrubber.

I. Continuous Compliance

1. CO Emission Limit

The March 2011 final rule requires sources subject to a CO emission limit to demonstrate compliance by measuring CO emissions while also monitoring the oxygen content of the exhaust. We are amending the monitoring requirements in 40 CFR 63.11224(a) to allow sources subject to a CO emission limit the option to install, operate, and maintain CO and oxygen CEMS. The CEMS must be installed, operated and maintained according to Performance Specifications 3 and 4, 4A, or 4B at 40 CFR part 60, appendix B, and according to the site-specific monitoring plan that each facility is required to develop. The CEMS will also be required to complete a performance evaluation, also according to Performance Specifications 3 and 4, 4A, or 4B.

Sources have the option to demonstrate continuous compliance by monitoring both CO and oxygen using CEMS to demonstrate compliance with the CO emission limit, corrected to 3 percent oxygen, or monitoring and complying with an oxygen content operating limit that is established during the performance stack test. Sources that use CO and oxygen CEMS are not required to perform initial CO performance testing nor are they subject to oxygen content operating limit requirements. Sources that choose to demonstrate continuous compliance by monitoring and complying with an oxygen content operating limit must install, operate, and maintain an oxygen analyzer system at or above the minimum percent oxygen by volume that is established as the operating limit for oxygen when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. We have removed the requirement that the oxygen monitor be located at the outlet of the boiler, so that it can be located either within the combustion zone or at the outlet as a flue gas oxygen monitor.

We are amending the oxygen monitoring requirements to allow for the use of oxygen trim systems and have included oxygen trim systems in the definition of ''oxygen analyzer system.'' We have clarified that operation of oxygen trim systems to meet the oxygen monitoring requirements shall not be done in a manner that compromises furnace safety. The definitions of ''oxygen analyzer system'' and ''oxygen trim system'' in 40 CFR 63.11237 read as follows:

- *Oxygen analyzer system* means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location. This definition includes oxygen trim systems.
- *Oxygen trim system* means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller.

2. Tune-Up Standards

The EPA is amending the requirements for demonstrating continuous compliance with the work practice and management practice tune-up standards in 40 CFR 63.11223 to clarify that CO measurements that are required before and after tune-up adjustments may be taken using a portable CO analyzer. We are clarifying that the requirements to inspect the burner and the system controlling the air-to-fuel ratio may be delayed until the next scheduled shutdown. We are also clarifying that units that produce electricity for sale may delay these inspections until the first outage, not to exceed 36 months from the previous inspection. In addition, we are clarifying that optimization of CO emissions should be consistent with any NO_X requirements to which the unit is subject. Finally, we are specifying for units that are not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.

3. Performance Testing Frequency

The EPA is amending 40 CFR 63.11220 to specify in paragraph (b) that the owner or operator of an affected boiler does not need to conduct further PM emissions testing if, when demonstrating initial compliance with the PM emission limit, the performance test results show that the PM emissions are equal to or less than half of the PM emission limit. The owner or operator must continue to comply with all applicable operating limits and monitoring requirements. If the initial performance test results show that the PM emissions are greater than half of the PM emission limit, the owner or operator must conduct subsequent performance tests as specified in 40 CFR 63.11220(a).

We are clarifying in 40 CFR 63.11220(d) that existing affected boilers that have not operated since the previous compliance demonstration must complete their subsequent compliance demonstration no later than 180 days after the re-start of the affected boiler.

4. Fuel Analysis

The EPA is amending 40 CFR 63.11220 to specify in paragraph (c) that the owner or operator of an affected coal-fired boiler does not need to conduct further fuel analysis sampling if, when demonstrating initial compliance with the Hg emission limit, the Hg constituents in the fuel or fuel

mixture are measured to be equal to or less than half of the Hg emission limit. The owner or operator must continue to comply with all applicable operating limits and monitoring requirements.

When demonstrating initial compliance with the Hg emission limit, if the Hg constituents in the fuel or fuel mixture are greater than half of the Hg emission limit, the owner or operator must conduct quarterly sampling.

5. Averaging Times

The EPA is amending the averaging time for parameter monitoring and compliance with operating limits to a 30-day rolling average.

The EPA is revising the definitions of ''30-day rolling average'' and ''daily block average'' to exclude periods of startup and shutdown and periods when the unit is not operating in the calculation of the arithmetic mean.

6. Monitoring Data

The EPA is clarifying in 40 CFR 63.11221 the monitoring data collection requirements.

J. Periods of Startup and Shutdown

1. Definitions

The EPA is revising the definitions of ''startup'' and ''shutdown'' such that they are tailored for industrial boilers and are consistent with the definitions of ''startup'' and ''shutdown'' in the 40 CFR part 63, subpart A General Provisions. The revised definitions reflect the fact that industrial boilers function to provide steam or, in the case of cogeneration units, electricity. We are defining startup as the period between either the first-ever firing of fuel in the boiler or the firing of fuel in the boiler after a shutdown and when the boiler first supplies steam or heat. We are defining shutdown as the period between either when no more steam or heat is supplied by the boiler or no fuel is being fired in the boiler and when there is no steam and no heat being supplied and no fuel being fired in the boiler.

2. Compliance With Operating Limits

The EPA has clarified that operating limits must be met at all times except during periods of startup and shutdown.

3. Minimization of Startup and Shutdown Periods

The EPA is amending 40 CFR 63.11223(g) to include biomass- and oil-fired boilers in the requirement to minimize the time spent in startup and shutdown periods. Specifically, the requirement is to minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available must be followed.

K. Affirmative Defense Language

In this final rule, the EPA is updating the affirmative defense provisions for malfunctions that were included in the March 21, 2011, final rule. We have made certain changes to 40 CFR 63.11226 to clarify the circumstances under which a source may assert an affirmative defense. The changes clarify that a source may assert an affirmative defense to a claim for civil penalties for violations of standards that are caused by malfunctions. A source can avail itself of the affirmative defense when there has been a violation of the emission standards due to an event that meets the definition of malfunction under 40 CFR 63.2 and qualifies for assertion of an affirmative defense under 40 CFR 63.11226. In the March 2011 final rule, we used terms such as ''exceedance'' or ''excess emissions'' in 40 CFR 63.11226, which created unnecessary confusion as to when the affirmative defense could be used. In this final rule, we have eliminated those terms and used the word ''violation'' to make clear that the affirmative defense to civil penalties is available only where an event that causes a violation of the emissions standard meets the criteria for the assertion of an affirmative defense under 40 CFR 63.11226.

This final rule requires that to establish the affirmative defense the owner must prove by a preponderance of evidence that repairs were made as expeditiously as possible when a violation occurs. We have re-evaluated the language concerning the use of off-shift and overtime labor, to the extent practicable, to make the repairs and believe that the language is not necessary. Thus, the language has been eliminated from this final rule.

We have also eliminated the 2-day notification requirement that was included in 40 CFR 63.11226(b) of the March 2011 final rule because we expect to receive sufficient notification of malfunction events that result in violations in other required compliance reports as specified under 40 CFR 63.11225. In addition, we have revised the 45-day affirmative defense reporting requirement that was included in 40 CFR 63.11226(b) of the March 2011 final rule. This final rule requires sources to include the report in the first compliance, deviation or excess emission report due after the initial occurrence of the violation, unless the compliance, deviation or excess emission report is due less than 45 days after the violation. In that case, the affirmative defense report may be included in the second compliance, deviation or excess emission report due after the initial occurrence of the violation. Because the affirmative defense report is now included in a subsequent compliance, deviation or excess emission report, there is no longer a need for the 30-day extension for submitting a stand-alone affirmative defense report. Consequently, we are not including that provision in this final rule.

L. Notification, Recordkeeping and Reporting Requirements

The EPA is amending 40 CFR 63.11225(a)(2) to specify that existing affected boilers have until January 20, 2014 to submit their Initial Notification.

The EPA is amending 40 CFR 63.11225(c)(2) to specify that records of fuel use and type are required only for boilers that are subject to numerical emission limits. We are also amending 40 CFR 63.11223(b) to clarify that the type and amount of fuel needs to be included in reports only if the boiler was physically and legally capable of using more than one type of fuel during that time period and that the report should include concentrations of CO and oxygen, measured at high fire or typical operating load, before and after the tune-up of the boiler. Finally, we are specifying that for units sharing a fuel meter, the fuel use by each boiler may be estimated.

The EPA is amending 40 CFR 63.11225(b) to clarify the requirements for submitting a biennial or 5-year report for units that are only subject to tune-up requirements and to specify the information that must be included in the annual, biennial, or 5-year compliance report.

We are amending 40 CFR 63.11225(c)(2) to specify, as applicable, that a copy of the energy assessment, records documenting the days of operation for each boiler that meets the definition of a seasonal boiler, and a copy of the federally enforceable permit for each boiler that meets the definition of a limited-use boiler must be maintained.

We are revising 40 CFR 63.11225(d) to remove the requirement that the most recent 2 years of records be maintained on site and are adding language that allows for computer access or other means of immediate access of records stored in a centralized location.

We are adding a new paragraph 40 CFR 63.11225(g) to require that boilers that switch fuels, make a physical change, or take a permit limit that results in the applicability of a different subcategory within subpart JJJJJJ, a switch out of subpart JJJJJJ, or the applicability of subpart JJJJJJ must provide notification within 30 days of the fuel switch, physical change, or permit limit. 40 CFR 63.11225(g) also specifies what information the notification must include.

M. Title V Permitting Requirements

For the reasons stated in our March 21, 2011, final rule (76 FR 15554) as well as our reconsideration proposal (76 FR 80532, December 23, 2011), the EPA is not making any changes to the title V exemption for area sources. Thus, no area sources subject to subpart JJJJJJ are required to obtain a title V permit as a result of being subject to subpart JJJJJJ.

Facilities that are synthetic area sources for HAP under subpart JJJJJJ may already be covered by a title V permit or may be required to obtain a title V permit in the future for a reason other than subpart JJJJJJ. For example, area source boilers could be major sources of non-HAP pollutants or could be located at sources that are subject to title V. Thus, the title V exemption in subpart JJJJJJ does not affect whether or not these area sources under subpart JJJJJJ are otherwise required to obtain a permit under part 70 or part 71. See 40 CFR 70.3(a) and (b) or 71.3(a) and (b).

N. Definition of Period of Gas Curtailment or Supply Interruption

We are amending the definition of ''period of natural gas curtailment or supply interruption'' in 40 CFR 63.11237 to clarify that a curtailment does not include normal market fluctuations in the price of gas that are not associated with periods of supplier delivery restrictions. We are also amending the definition to indicate that periods of supply interruption that are beyond control of the facility can also include on-site natural gas system emergencies and equipment failures, and that legitimate periods of supply interruption are not limited to off-site circumstances. We are revising the term and the definition so that it includes the curtailment of any gaseous fuel, and is not limited to just natural gas. Finally, we are clarifying that the supply of gaseous fuel is to an ''affected boiler'' rather than ''affected facility'' and that the supply of gaseous fuel is ''restricted or halted'' for reasons beyond the control of the facility. The definition is amended to read as follows:

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

O. Miscellaneous Technical Corrections

In addition to the above summary of the EPA's final action regarding provisions identified for reconsideration and on other discrete matters identified in response to comments or data received during the comment period, other definitional and regulatory text revisions are being made. These clarifications will help affected sources determine their applicability and better understand the rule requirements. In some instances, definitions and regulatory text have been revised or added to correspond with other related rules, especially the emission standards for industrial, commercial, and institutional boilers at major sources of HAP (40 CFR part 63, subpart DDDDD). Section IV of this preamble includes additional details regarding these miscellaneous technical corrections.

P. Other Issues

40 CFR 63.11196(a)(1) of the March 21, 2011, final rule (76 FR 15554) requires that owners and operators of existing affected boilers subject to the tune-up requirement complete the initial boiler tune-up by March 21, 2012. In addition, 40 CFR 63.11225(a)(4) requires that owners and operators of existing affected boilers subject to the tune-up requirement submit their Notification of Compliance Status no later than 120 days after the applicable compliance date specified in 40 CFR 63.11196. That means that those owners and operators were required to submit their Notification of Compliance Status by July 19, 2012. The Notification must include, among other information, a certification that states ''This facility complies with the requirements in § 63.11214 to conduct an initial tune-up of the boiler.''

On March 13, 2012, the EPA issued a No Action Assurance (NAA) to all owners and/or operators of existing industrial boilers and commercial and institutional boilers at area sources of HAP emissions stating that we would not enforce the requirement to conduct an initial tune-up by March 21, 2012. The NAA was primarily based upon the EPA's concern that sources were reporting a shortage of qualified individuals to prepare boilers for tune-ups and then conduct those tune-ups by the regulatory deadline, as well as upon the uncertainty in the regulated community resulting from the pending reconsideration of the Area Source Boiler Rule. The March 13, 2012, NAA states that it remains in effect until either (1) 11:59 p.m. EDT, October 1, 2012, or (2) the effective date of a final rule addressing the proposed reconsideration of the Area Source Boiler Rule, whichever occurs earlier.

As the July 19, 2012, Notification of Compliance Status deadline approached, a final rule addressing the proposed reconsideration of the Area Source Boiler Rule had not been issued, and thus the NAA continued to remain in effect. Nothing that the EPA learned since the issuance of the original NAA letter led us to question our original concerns about the feasibility of all sources timely completing an initial tune-up. Further, sources that did not complete a tune-up could not certify that they conducted one. Thus, on July 18, 2012, the EPA extended the NAA for sources required to complete an initial tune-up by March 21, 2012, to also include the deadline for submitting the Notification of Compliance Status regarding the initial tune-up. In addition, given that no final rule addressing the proposed reconsideration of the Area Source Boiler Rule had been issued as of July 18, 2012, the pending reconsideration continued to create uncertainty in the regulated community. Thus, the NAA letter also amended the expiration date of the March 13, 2012, NAA, such that the NAA would remain in effect until either (1) 11:59 p.m. EST, December 31, 2012, or (2) the effective date of a final rule addressing the proposed reconsideration of the Area Source Boiler Rule, whichever occurs earlier.

This final rule revises the compliance date for existing affected boilers subject to a tune-up from March 21, 2012, to March 21, 2014. The July 19, 2012, deadline for submitting the Notification of Compliance Status regarding the initial tune-up is reset to July 19, 2014, as a result of revising the compliance date for existing affected boilers subject to a tune-up to March 21, 2014. Owners or operators that had not yet conducted their boiler tune-up, but submitted a Notification of Compliance Status by July 19, 2012, simply to notify the EPA

that the tune-up had not been completed, will need to submit a revised Notification of Compliance Status after their boiler tune-up is conducted.

IV. Summary of Significant Changes Since Proposed Action on Reconsideration

Numerous changes are being made to the March 2011 final rule based on the public comments received. Most of the changes are editorial to clarify applicability and implementation issues raised by the commenters. The public comments received on the proposed changes and the responses to them can be viewed in the memorandum "*Summary of Public Comments and Responses for: National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers*" located in the docket.

A. Applicability

Since proposal, changes to the applicability of this final rule have been made.

1. Dual-Fuel Fired Boilers

The March 2011 final rule includes as a new affected source a boiler that commences fuel switching from natural gas to solid fossil fuel, biomass, or liquid fuel after June 4, 2010. For example, under the March 2011 final rule, if an unaffected gas-fired boiler currently burns oil as allowed under the definition of gas-fired boiler, but after June 4, 2010 burns oil for reasons not allowed under the definition of gas-fired, these boilers would become new affected oil-fired units. The December 2011 reconsideration action did not propose any revisions to the provisions regarding boilers that fuel switch after June 4, 2010. However, the EPA has been made aware through public comments that many dual-fuel fired units presently burn primarily natural gas with limited or no amounts of oil, and that these units may want to burn oil in the future for reasons not allowed under subpart JJJJJJ's definition of gas-fired (*e.g.* cost). Under the March 2011 final rule, such an existing dual-fuel gas-fired boiler that wanted to avoid being subject to the new source requirements would notify as an existing oil-fired unit and be subject to the requirements for existing oil-fired boilers.

We received public comments regarding rule applicability and compliance requirements for these existing dual-fuel fired boilers. One commenter asserted that regardless of the fuel capability identified in an initial notification, the distinction between a new source and an existing source should only be made based upon a source's capability to burn a particular fuel as of the effective date of the rule. The commenter explained that many facilities have boilers that can burn either gas or liquid and, because the price of gas is currently lower than the price of most liquid fuels, they likely are currently firing gas during normal operation, with liquid being fired only during periods of curtailment. The commenter pointed out that, in the future, the price of liquid fuel may be lower than the price of gaseous fuel, and facilities may want to preferentially burn liquid fuel over gas fuel. The commenter asserted that a change in the fuel from the initial notification should not, in and of itself, reclassify a source as a new source for purposes of subpart JJJJJJ. Further, the commenter asserted that their interpretation is comparable to the fuel switching provisions in the EPA's NSPS and PSD regulations. The same commenter asserted that if a source already has oil or alternate fuel capability, then that source would not be commencing construction or making a change to the source. The commenter explained that many of these facilities with boilers capable of burning fuel oil as a back-up for natural gas may not have submitted an initial notification since gaseous fuel-fired boilers that only burn liquid during periods of curtailment are not covered by the Area Source Boiler Rule. The commenter maintained the EPA's guidance, that a dual-fuel fired boiler that fails to file an initial notification and then plans to burn oil in the future would be considered to be a new source, appears to be contrary to regulatory text stating that an affected source is a new source if construction or reconstruction of the affected source is commenced after June 4, 2010 and the applicability criteria are met at the time construction is commenced. The commenter suggested that the EPA clarify that to become a new source, the source must be altered to be capable of accommodating a new fuel, so that new sources are not created simply by failing to submit an initial notification or a notice of fuel switching for a unit that is already capable of accommodating that fuel. Another commenter explained that owners and operators of dual-fuel fired boilers anticipate firing natural gas for many years to come, or until gas supply is temporarily curtailed outside of their control or until such a time when fuel oil becomes more cost effective to burn than gas. The commenter asserted that, based on common sense and increased flexibility, these dual-fuel fired boilers normally burning gas could not be considered subject to any oil-fired requirements as long as they continue to fire only gas, except under the regulation's stated exemptions for burning oil.

In addition to carefully considering the public comments received regarding dual-fuel fired boilers, the EPA reconsidered its overall intent with regard to existing dual-fuel fired boilers that fuel switch after June 4, 2010. Consequently, in this final rule, we are revising the provisions regarding existing boilers that fuel switch after June 4, 2010. This final rule amends 40 CFR 63.11194 to specify that an existing dual-fuel fired boiler (*i.e.,* commenced construction or reconstruction on or before June 4, 2010) meeting the definition of gas-fired boiler, as defined in 40 CFR 63.11237, that meets the applicability requirements of subpart JJJJJJ after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel. A new or reconstructed dual-fuel fired boiler (*i.e.,* commenced construction or reconstruction after June 4, 2010) meeting the definition of gas-fired boiler, as defined in 40 CFR 63.11237, that meets the applicability criteria of subpart JJJJJJ after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be a new source under this subpart. This revision maintains consistency with the rule's applicability criteria for determining new versus existing sources, eliminates the requirement that existing dual-fuel fired boilers notify as affected sources although, at the time, they are not subject to subpart JJJJJJ, and promotes flexibility in that these existing dual-fuel fired sources that were designed to accommodate an alternate fuel may fire the alternate fuel and move into subpart JJJJJJ without being subject to the more stringent requirements for new boilers.

2. Residential Boilers

One commenter suggested that the definition of "residential boiler," as proposed, be revised to acknowledge the use of combined heat and power systems which function with heat and/or hot water systems. The EPA agrees and is amending the proposed definition to clarify that a boiler that operates as part of a residential combined heat and power system (and that meets other definitional requirements) is a residential boiler. Another commenter explained that

historical buildings may be subdivided into more than four units but boilers serving those units should still be considered residential boilers. We agree and, in this final rule, are amending the proposed definition to clarify that a boiler serving a single unit residence dwelling that has since been converted or subdivided into condominiums or apartments may also be considered a residential boiler.

3. Temporary Boilers

One commenter supported the EPA's 12-month threshold above which the boiler would no longer be considered temporary but pointed out that a boiler used on a temporary basis during construction of a commercial building may be needed for more than 12 months due to the length of the construction period. The commenter suggested that the definition of temporary boiler, as proposed, be revised to allow owners or operators to petition for an extension beyond 12 months. We agree with the commenter and, in this final rule, are amending the proposed definition to allow an owner or operator to submit to their regulatory agency a petition for an extension beyond 12 months. Another commenter suggested that the EPA expand on the intent of "location" in the definition of "temporary boiler." We are amending the proposed definition to clarify that "location" means "location within the facility." This clarification will allow a boiler to be moved from one location to another within a facility and be considered a different temporary boiler (*i.e.,* a new time period begins) as long as the boiler does not continue to perform the same or similar function and to serve the same electricity, steam, and/or hot water system. Another commenter pointed out that our definition, as proposed, does not specify a time period associated with the statement "Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period." The commenter explained that it is not unusual for a temporary boiler to be used for short periods during turnarounds or other maintenance activities that recur several years apart. Under the proposal, these boilers would not be considered temporary because each boiler replaces the previous one and performs the same function, even though there is a multi-year gap between the occurrences. The commenter suggested that replacements that occur after a gap of at least one year should not be considered consecutive for the purposes of the definition. We agree with the commenter and are amending numbered paragraph (2) in the proposed definition of "temporary boiler" such that it specifies that "Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period *unless there is a gap in operation of 12 months or more.*".

4. Seasonal Boilers

Several commenters explained that boilers subject to semi-annual testing requirements would not meet the proposed 7 consecutive month shutdown criteria, but otherwise would be considered seasonal boilers. Commenters suggested that seasonal boiler be defined to allow periodic testing during the 7-month shutdown period. We agree with the commenters and, in this final rule, are revising the proposed definition of seasonal boiler to allow for a combined total of 15 days of use during the shutdown period for periodic testing.

Another commenter pointed out that the EPA's seasonal boiler definition, as proposed, would potentially allow more regular use. The commenter specifically suggested that the proposed definition be revised to clarify that there must be a 7 consecutive month shutdown every 12 months. It was the EPA's intent that the shutdown period of at least 7 consecutive months be on a 12-month basis. In response to this comment, we are clarifying in the definition of seasonal boiler that the shutdown must be for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period.

5. Limited-Use Boilers

Several commenters asserted that the EPA should also include a limited-use subcategory in the area source rule for the same reasons we determined a seasonal boiler subcategory was appropriate. Commenters suggested that we should apply the same 5-year tune-up cycle for limited-use units such as auxiliary boilers that we proposed for seasonally-operated units and small oil-fired units. Commenters explained that in the electric utility industry, auxiliary boilers are typically used to generate the steam necessary to bring a main EGU on line during startup and, since auxiliary boilers are primarily operated during unit startup, operation for many of these boilers is typically very limited and sporadic. Commenters also pointed out that the Major Source Boiler Rule includes a limited-use subcategory.

The EPA has determined that a limited-use subcategory is appropriate and is including a limited-use subcategory in this final Area Source Boiler Rule. Specifically, a limited-use boiler is defined in this final rule to mean any boiler that burns any amount of solid or liquid fuels and has a federally enforceable average annual capacity factor of no more than 10 percent. We are using a capacity-factor approach for the same reasons that the approach is being used in the Major Source Boiler Rule. A capacity-factor approach allows operational flexibility for units that operate on standby mode or low loads for periods longer than would be allowed under an approach that limited hours of operation (*e.g.,* the 876 hours per year included in the proposed limited-use definition for major source boilers). The operational flexibility associated with a capacity-factor approach can be achieved without increasing emissions or harm to human health and the environment. Units operating at 10 percent load for 8,760 hours per year would emit the same amount of emissions as units operating at full load for 876 hours per year. Further, it is technically infeasible to test these limited-use boilers since these units serve as back-up energy sources and their operating schedules can be intermittent and unpredictable.

This final rule specifies that limited-use boilers are required to complete a tune-up every 5 years. Boilers that operate no more than 10 percent of the year (*i.e.,* a limited-use boiler) would operate for no more than 6 months in between tune-ups on a 5-year tune-up cycle. The brief period of operations is even less than the number of operating months that seasonal boilers and full-time boilers will operate between tune-ups. The irregular schedule of operations also makes it difficult to schedule more frequent tune-ups. We believe that establishing a limited-use subcategory is reasonable.

6. Alternative PM Emission Control for Certain Oil-Fired Boilers

The EPA received a number of comments urging that we provide an exemption from the PM limit for units burning low-sulfur liquid fuel as is provided in subpart Dc of 40 CFR part 60 (standards of performance for new small industrial-commercial-institutional steam generating units). Commenters asserted that such an exemption is justified since the low sulfur content indicates low PM emissions and that boilers firing low-sulfur liquid fuel should only be subject to a requirement to maintain records documenting the liquid fuel fired. We agree burning low-sulfur liquid fuel can be an alternative method of meeting GACT for PM. We are amending 40 CFR

63.11210 to specify that new or reconstructed oil-fired boilers that combust 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 emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce PM or sulfur dioxide emissions meet GACT for PM providing the type of fuel combusted is monitored and recorded on a monthly basis. Further, we are specifying that if you intend to burn a new type of fuel or fuel mixture that does not meet the requirements of this paragraph, you must conduct a performance test within 60 days of burning the new fuel.

B. Tune-Up Requirements

1. Boilers With Oxygen Trim Systems

In this final rule, the EPA is adding to the types of boilers that must conduct a tune-up every 5 years boilers that have an oxygen trim system that maintain an optimum air-to-fuel ratio that would otherwise be subject to biennial tune-ups. These units do not need to be tuned as frequently as other types of boilers because the trim system is designed to maintain an optimum air-to-fuel ratio which is the purpose of a tune-up.

2. Initial Compliance for Existing Boilers

The EPA is revising the initial compliance date for existing boilers subject to the work practice or management practice standard of a tune-up. Under the proposed rule, owners and operators of existing affected boilers would have had to comply with the final rule by March 21, 2013. We solicited comments on whether to extend the compliance date to March 21, 2014. We received no comments objecting to either of these dates. Support for an extension until 2014 came from a variety of stakeholders affected by the rule. Therefore, this final rule requires that if you own or operate an existing boiler subject to a work practice or management practice standard of a tune-up, you must comply with the final rule no later than March 21, 2014.

3. Compliance Demonstration

We solicited comment on the requirements for demonstrating compliance with the work practice and management practice tune-up standards, with one focus on clarifying how to measure CO. Commenters requested that we clarify that CO measurements may be taken with a portable CO analyzer. We agree that this clarification is appropriate and are including this clarification in this final rule.

C. Energy Assessment

The EPA received a number of comments regarding the energy assessment requirements and in this final rule is making a series of changes to the energy assessment provisions and related definitions that clarify terms used and better set the scope of the assessment.

In this final rule, we are revising the definition of energy assessment by providing a duration for performing the energy assessment for numbered paragraph (3) in the definition of "energy assessment" in 40 CFR 63.11237 for facilities with units with greater than 1 TBtu/yr heat input capacity to specify time duration/size ratio and are including a cap to the maximum number of on-site technical hours that should be used in the energy assessment. The energy assessment for facilities with affected boilers and process heaters with greater than 1.0 TBtu/yr heat input capacity will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 technical hours, but may be longer at the discretion of the owner or operator.

The revised definition of energy assessment also clarifies our intentions that the scope of assessment is based on energy use by discrete segments of a facility, which could vary significantly depending on the site and its complexity, and not by a total aggregation of all individual energy using elements of a facility. We are adding the following language, as paragraph (4), to the "energy assessment" definition to help resolve current problems and allow for more streamlined assessments:

"(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) energy output in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (*e.g.*, product X manufacturing area; product Y drying area; Building Z)."

In this final rule, we are revising 40 CFR 63.11201 and Table 2 to subpart JJJJJJ to allow a source that is operating under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected boilers, by March 21, 2014, to satisfy the energy assessment requirement. In addition, we are clarifying that energy assessor approval and qualification requirements are waived in instances where an energy assessment completed on or after January 1, 2008 meets or is amended to meet the energy assessment requirements in this final rule by March 21.

The definition of "boiler system" is being revised in this final rule to clarify that it means the boiler and associated components directly connected to and serving the energy use systems.

The definition of "energy use system" is also being revised in this final rule to clarify that energy use systems are only those on-site systems using energy clearly produced by affected boilers.

D. Clarification of Oxygen Concentration Operating Limits

We are clarifying in this final rule that operating limits for oxygen concentration must be at or above the minimum established during a performance stack test. We are also clarifying that these limits are applicable when the unit is firing the fuel or fuel mixture utilized during the CO performance test.

E. Definitions Regarding Averaging Times

The EPA received comments requesting that we clarify that periods of startup and shutdown are excluded from calculation of the arithmetic mean in the definitions of "30-day rolling average" and "daily block average." We agree with the commenters and, in this final rule, are revising the definitions accordingly.

F. Fuel Sampling Frequency

The EPA is amending the fuel sampling requirements in 40 CFR 63.11220(c) because we realized that when performance stack testing requirements were revised in the March 2011 final rule we neglected to revise the fuel analysis requirements. In this final rule, we are specifying that the owner or operator does not need to conduct further fuel analysis sampling if, when demonstrating initial compliance with the Hg emission limit, the Hg constituents in the fuel or fuel mixture are measured to be equal to or less than half of the Hg emission limit. If, when demonstrating initial compliance, the Hg constituents in the fuel or fuel mixture are greater than half of the Hg emission limit, the owner or operator must conduct quarterly sampling.

G. Performance Testing Frequency

The EPA is amending the PM performance testing requirements in 40 CFR 63.11220(b) to specify that the

owner or operator of an affected boiler does not need to conduct further PM emission testing if, when demonstrating initial compliance with the PM emission limit, the performance test results show that the PM emissions are equal to or less than half of the PM emission limit. The owner or operator must continue to comply with all applicable operating limits and monitoring requirements. If the initial performance test results show that the PM emissions are greater than half of the PM emission limit, the owner or operator must conduct subsequent performance tests as specified in 40 CFR 63.11220(a).

With respect to the reconsideration issue regarding the GACT-based PM standards for new oil-fired boilers, we received comments asserting that the most effective control strategy for small oil-fired boilers is the tune-up required by the standards and that establishing a PM limit for those boilers between 10 MMBtu/hr and 30 MMBtu/hr just ensures that those boilers will do stack testing demonstrating that the boilers are in compliance without the need for controls; a fact already known. Commenters also asserted that establishing a PM limit imposes a stack test obligation on small facilities with the least resources to deal with the testing.

We have reviewed the comments and are not eliminating or revising the PM limit for new oil-fired boilers with heat input capacity between 10 MMBtu/hr and 30 MMBtu/hr. We do however, believe that adjustments to the PM performance test frequency as described above are appropriate for boilers that demonstrate during their initial performance test that their PM emissions are equal to or less than half of the PM limit. We believe that the performance test adjustment should not be potentially applicable to only new oil-fired boilers with heat input capacity between 10 MMBtu/hr and 30 MMBtu/hr, but to all new boilers. Owners or operators of boilers whose initial performance test results show that their PM emissions are equal to or less than half of the PM emission limit and, thus, do not need to conduct further PM emissions testing, must continue to comply with all applicable operating limits and monitoring requirements to ensure that there are no changes in operation of the boiler or air pollution control equipment that could increase emissions. This adjustment in PM performance test frequency will potentially reduce the burden on small entities operating boilers that meet the adjustment criteria.

H. Startup and Shutdown Definitions

A number of commenters indicated that the proposed load specifications (*i.e.,* 25 percent load) within the definitions of ''startup'' and ''shutdown'' were inconsistent with either safe or normal (proper) operation of the various types of boilers encountered within the source category. As the basis for defining periods of startup and shutdown, a number of commenters suggested alternative load specifications based on the specific considerations of their boilers; other commenters suggested the achievement of various steady-state conditions.

We have reviewed these comments and believe adjustments are appropriate in the definitions of ''startup'' and ''shutdown.'' These adjustments are tailored for industrial boilers 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 industrial boilers function to provide steam or, in the case of cogeneration units, electricity. Therefore, industrial boilers should be considered subject to applicable standards at all times steam of the proper pressure, temperature and flow rate is being provided to a common header system or energy user(s) for use as either process steam or for the cogeneration of electricity. The definitions of ''startup'' and ''shutdown'' have been revised in this final rule as follows:

Startup means either the first-ever firing of fuel in a boiler for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler.

I. Notifications

1. Initial Notification

The EPA has been made aware that there are many affected boilers at area sources that are just becoming aware, or are not yet aware, that they are subject to emission standards. Thus, we are amending 40 CFR 63.11225(a)(2) to allow these sources until January 20, 2014 to submit their Initial Notification.

2. Notification of Fuel Change, Physical Change, or Permit Limit

The notification requirement in 40 CFR 63.11225(g) of the final rule for instances when a change in fuel or a physical change to a boiler results in the applicability of a different subcategory or a change out of subpart JJJJJJ is being revised. Under the proposed reconsideration action, a facility would have been required to provide 30 days prior notice of the date upon which the change was scheduled to occur. Commenters explained that an advanced notification requirement would delay such a change if the owner or operator decided to immediately make a change (*e.g.,* switch to 100 percent natural gas) and could potentially restrict flexibility in manufacturing operations, and suggested that the owner or operator be allowed to make notification within 30 days after the change has occurred. We agree that notification within 30 days after a change that results in applicability of a different subcategory or a change out of subpart JJJJJJ will provide the EPA or state/local agency with the required information within a reasonable timeframe. Thus, in this final rule, we are requiring facilities making these types of changes to provide notification within 30 days following the change. The notification requirement in 40 CFR 63.11225(g) is also being amended to clarify that it includes affected boilers that switch fuels or make a physical change to the boiler and the fuel switch or change results in the applicability of a different subcategory within subpart JJJJJJ, in the boiler becoming subject to subpart JJJJJJ, or in the boiler switching out of subpart JJJJJJ due to a change to 100 percent natural gas, as well as affected boilers that take a permit limit that results in the applicability of subpart JJJJJJ. Commenters requested that we make this clarification and we agree that it is appropriate.

J. Miscellaneous Definitions

In this final rule, we are revising some definitions and adding others to help affected sources determine their applicability. Specifically, definitions have been added for the terms ''10-day rolling average,'' ''30-day rolling average,'' ''Annual heat input,'' ''Biodiesel,'' ''Calendar year,'' ''Common stack,'' ''Daily block average,'' ''Distillate oil,'' ''Electric boiler,'' ''Electric utility steam generating unit (EGU),'' ''Energy management program,'' ''Fluidized bed boiler,'' ''Fluidized bed combustion,'' ''Hourly average,'' ''Limited-use boiler,'' ''Load fraction,''

''Minimum scrubber pressure drop,'' ''Minimum sorbent injection rate,'' ''Minimum total secondary electric power,'' ''Operating day,'' ''Oxygen analyzer system,'' ''Oxygen trim system,'' ''Process heater,'' ''Regulated gas stream,'' ''Residential boiler,'' ''Residual oil,'' ''Seasonal boiler,'' ''Shutdown,'' ''Solid fuel,'' ''Startup,'' ''Temporary boiler,'' ''Tune-up,'' ''Vegetable oil,'' ''Voluntary Consensus Standards (VCS),'' and ''Wet scrubber.''

Definitions revised to clarify the term include ''Bag leak detection system,'' ''Biomass subcategory,'' ''Boiler,'' ''Boiler system,'' ''Deviation,'' ''Dry scrubber,'' ''Electrostatic precipitator (ESP),'' ''Energy assessment,'' ''Energy use system,'' ''Federally enforceable,'' ''Gas-fired boiler,'' ''Heat input,'' ''Hot water heater,'' ''Institutional boiler,'' ''Liquid fuel,'' ''Minimum activated carbon injection rate,'' ''Minimum oxygen level,'' ''Minimum scrubber liquid flow rate,'' ''Natural gas,'' ''Oil subcategory,'' ''Particulate matter,'' ''Period of gas curtailment or supply interruption,'' ''Qualified Energy Assessor,'' and ''Waste heat boiler.''

V. Other Actions the EPA Is Taking

Section 307(d)(7)(B) of the CAA states 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. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time 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, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b)).''

As to the first procedural criterion for reconsideration, a petitioner must show why the issue could not have been presented during the comment period, either because it was impracticable to raise the issue during that time or because the grounds for the issue arose after the period for public comment (but within 60 days of publication of the final action). The EPA is denying the petitions for reconsideration of five issues because this criterion has not been met. In many cases, the petitions reiterate comments made on the proposed June 2010 rule during the public comment period for that rule. On those issues, the EPA responded to those comments in the March 2011 final rule, and made appropriate revisions to the proposed rule after consideration of public comments received. It is well established that an agency may refine its proposed approach without providing an additional opportunity for public comment. See *Community Nutrition Institute* v. *Block,* 749 F.2d 50, 58 (DC Cir. 1984) and *International Fabricare Institute* v. *EPA,* 972 F.2d 384, 399 (DC Cir. 1992) (notice and comment is not intended to result in ''interminable back-and-forth[,]'' nor is agency required to provide additional opportunity to comment on its response to comments) and *Small Refiner Lead Phase-Down Task Force* v. *EPA,* 705 F.2d 506, 547 (DC Cir. 1983) (''notice requirement should not force an agency endlessly to repropose a rule because of minor changes'')

In the EPA's view, an objection is of central relevance to the outcome of the rule only if it provides substantial support for the argument that the promulgated regulation should be revised. See *Union Oil* v. *EPA,* 821 F.2d 768, 683 (DC Cir. 1987) (court declined to remand rule because petitioners failed to show substantial likelihood that final rule would have been changed based on information in petition). See also the EPA's *Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202 of the Clean Air Act,* 75 FR at 49556, 49561 (August 13, 2010). See also, 75 FR at 49556, 49560–49563 (August 13, 2010) and 76 FR at 4780, 4786—4788 (January 26, 2011) for additional discussion of the standard for reconsideration under CAA section 307(d)(7)(B).

We are denying reconsideration on the following five issues contained in the petitions for reconsideration because they failed to meet the standard described above for reconsideration under CAA section 307(d)(7)(B). Specifically, on these issues, the petitioner has failed to show the following: That it was impracticable to raise their objections during the comment period or that the grounds for their objections arose after the close of the comment period; and/or that their concern is of central relevance to the outcome of the rule. Therefore, the EPA is denying the petitions for reconsideration on the issues for the reasons described below.

Issue: Use of RDL Is Unlawful

The petitioner (Sierra Club) objected to the EPA establishing a MACT floor emission limit at a level equal to three times the RDL as being unlawful and arbitrary. This issue is not of central relevance to the outcome of this final rule. The final emission limits in this rule are based on the UPL at a confidence interval of 99 percent. The RDL analysis was not used in this final rule.

Issue: MACT Floor for Existing Sources Must Reflect Average Performance of the Top 12 Percent of Units

The petitioner (Sierra Club) stated that the MACT floor for existing sources must reflect the average performance of the top 12 percent of units. The petitioner has not demonstrated that it lacked the opportunity to comment on the EPA's MACT floor analysis. The methods used to compute the MACT floors were subject to notice and comment. Rationale and responses to comments on the MACT floor methodology were provided at 75 FR 31904, June 4, 2010; 76 FR 15571, March 21, 2011. Therefore, the EPA is denying the request for reconsideration.

Issue: Consider a De Minimis Size Threshold

The petitioners (American Petroleum Institute, National Petrochemical and Refiners Association, Alaska Oil and Gas Association) requested that the EPA consider a de minimis size threshold using guidelines from insignificance thresholds authorized under CAA part 71. The EPA is denying the request for reconsideration on this issue. In the June 2010 proposed rule, it was readily apparent that we were not establishing de minimis size thresholds in the area source rulemaking. We received multiple comments on this issue and responded to them in the response to comments document for the March 2011 final rule. The issue on which petitioners seek reconsideration was one that could have been raised during the comment period and thus does not meet the requirements for reconsideration. Therefore, the EPA is denying this request for reconsideration.

Issue: MACT Standards Must Be Set for All HAP

The petitioner (Sierra Club) asserted that MACT standards must be set for all HAP including HAP not listed in CAA section 112(c)(6). The EPA is denying the request for reconsideration on this issue. We disagree with the petitioner that the EPA must issue emission standards for all HAP. MACT standards have been set for Hg and CO, as a

surrogate for POM emissions, but the EPA does not interpret CAA section 112(c)(6) to compel regulation of all HAP emitted by area sources. The EPA's position on this issue was clear in the proposed rule (75 FR 31900, 31904, 31918). This commenter raised this issue in its comments (76 FR 15567, March 21, 2011). Not only did the petitioner have an opportunity to present its theory in its comments, but also it did so.

Issue: CO Is Not a Valid Surrogate for POM

The petitioner (Sierra Club) requested that the EPA remove the CO standard as a surrogate for POM and instead adopt a numeric limit for POM because CO is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of CO as a surrogate for POM, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA revised the final CO emission limit to ensure a more accurate correlation between POM and CO levels. The EPA made its position on this issue clear and explained the agency's basis for concluding that CO was an appropriate surrogate in the proposed rule (75 FR 31900, 31904, June 4, 2010). The petitioner raised this issue in its comments (Document ID: EPA–HQ–OAR–2006–0790–1982, Comments of Earthjustice, Sierra Club, Clean Air Task Force, and Natural Resources Defense Council, p. 4). Therefore, the EPA is denying the request for reconsideration.

VI. Impacts Associated With This Final Rule

The amendments contained in this final action are corrections that are intended to clarify, but not change, the coverage of the final rule. The clarifications and corrections should make it easier for owners and operators and for local and state authorities to understand and implement the requirements. The final amendments will not affect the estimated emission reductions, control costs or the benefits of the rule in substance. The amendments do not impose any additional regulatory requirements beyond those imposed by the previously promulgated boiler area source rule and, in fact, will result in a decrease in the burden on small facilities as a result of the reduction in the frequency of conducting tune-ups for seasonal boilers, limited-use boilers, small (equal to or less than 5 MMBtu/hr) oil-fired boilers and boilers using an oxygen trim system that maintain an optimum air-to-fuel ratio. Additionally, the burden will be reduced on facilities with existing large boilers that currently operate under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected boilers, because a one-time energy assessment will not be required. Burden will also be reduced on facilities with affected boilers that burn low-sulfur oil because, in lieu of needing to meet an emission limit, we consider low-sulfur oil combustion to be GACT for PM for those boilers. This change should allow sources currently complying with 40 CFR 60 subpart Dc to use the same compliance approach rather than needing to monitor limits. Further reduction in burden will occur in instances where initial compliance demonstrations with the Hg emission limit via fuel sampling or with the PM emission limit via performance stack testing show that the emissions are equal to or less than half the respective emission limit because no further sampling or testing of those boilers will be required.

As discussed in section III, the Hg emission limits for new and existing large (10 MMBtu/hr or greater) coal-fired area source boilers were revised because of an error discovered in the analysis conducted for the final rule. This technical correction resulted in an increase in the emission limit for Hg. As explained in the December 2011 proposal, we also revised our impacts analysis to be consistent with emission factor changes made to the Major Source Boiler Rule. The baseline emissions for area sources are calculated using the emission factors developed for the Major Source Boiler Rule because of insufficient data for area sources. Emission factor changes resulted in a higher baseline emission for Hg from coal-fired area source boilers. Consequently, the result of the increase in both baseline Hg emissions and Hg emission limits is that the overall reduction in Hg emissions does not change significantly from the estimated reduction for the promulgated rule.

In summary, as compared to the control costs estimated for the March 2011 final rule, this final rule will not result in any meaningful change in the capital and annual cost due to the increase in emission limits and the decrease in burden on small facilities.

VII. Statutory and Executive Order Reviews

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

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action" because it is likely to raise novel legal or policy issues. Accordingly, the EPA submitted this action to the 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

This action does not impose an information collection burden. This action results in no significant changes to the information collection requirements of the promulgated rule and will have no increased impact on the information collection estimate of projected cost and hour burden made and approved by OMB. In fact, the reduction in tune-up frequency for some boilers will result in less information collection burden. Therefore, the information collection request has not been revised. However, the OMB has previously approved the information collection requirements contained in the existing regulation (40 CFR part 63, subpart JJJJJJ) under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501, *et seq.* and has assigned OMB control number 2060–0668. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

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.[2]

[2] 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 size standards for small businesses at 13 CFR 121.201 (less than 500, 750, or 1,000 employees, depending on the specific NAICS Code under subcategory 325); (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

Continued

The RFA also allows an agency to "consider a series of closely related rules as one rule for the purposes of sections" 603 (initial regulatory flexibility analysis) and 604 (final regulatory flexibility analysis) in order to avoid "duplicative action." 5 U.S.C. section 605(c). These amendments and notice of final action on reconsideration are closely related to the final Area Source Boiler Rule, which the EPA signed on February 21, 2011, and that took effect on May 20, 2011. The EPA prepared a final regulatory flexibility analysis in connection with the final Area Source Boiler Rule. Therefore, pursuant to section 605(c), the EPA is not required to complete a final regulatory flexibility analysis for this rule (*i.e.,* the amendments and final action).

The EPA has been concerned with potential small entity impacts since it began developing the Area Source Boiler Rule. The EPA conducted outreach to small entities and, pursuant to section 609 of RFA, convened a Small Business Advocacy Review Panel (the Panel) on January 22, 2009, to obtain advice and recommendations from small entity representatives. Pursuant to the RFA, the EPA used the Panel's report and prepared both an initial regulatory flexibility analysis and a final regulatory flexibility analysis in connection with the closely related final Area Source Boiler Rule. Convening an additional Panel and preparing an additional final regulatory flexibility analysis would be procedurally duplicative and is unnecessary given that the issues here are within the scope of those considered by the Panel. Finally, we note that this action, which amends the Area Source Boiler Rule, will not impose any additional regulatory requirements beyond those imposed by the previously promulgated Area Source Boiler Rule and, in fact, the amendments will afford relief to some boilers.

D. Unfunded Mandates Reform Act

This action contains no new federal mandates under the provisions of Title II of the UMRA of 1995, 2 U.S.C. 1531–1538 for state, local, or tribal governments or the private sector. This action imposes no new 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 and 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. This rule finalizes amendments to aid with compliance.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This final rule will not impose new direct compliance costs on state or local governments, and will not preempt state law. 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 new direct effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

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 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. We estimate no significant changes for the energy sector for price, production, or imports.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA of 1995, Public Law No. 104–113, 12(d) (15 U.S.C. 272 note) directs the EPA to use 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 use available and applicable VCS.

This action does not involve any new 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 the level of protection provided to human health or the environment through the rule's requirements does not vary. Therefore, it does not have any disproportionately high or adverse human health or environmental effects on any population, including any minority or low-income population.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to

small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

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 reconsideration of a previous action that was a major rule under the CRA. However, today's action makes only certain limited revisions to the March 2011 rule and those revisions do not qualify as a major rule under the CRA. Therefore, this action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective February 1, 2013.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference.

Dated: December 20, 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. Revising paragraphs (b)(19), (b)(23), (b)(35), (b)(40), (b)(69), and (b)(70).

■ b. Removing and reserving paragraph (b)(53).

■ c. Adding paragraphs (b)(46), (b)(55), and (b)(76) through (83).

■ d. Adding paragraphs (p)(12) through (20).

■ e. Adding paragraph (r).

The revisions and additions read as follows:

§ 63.14 Incorporations 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) and table 6 to subpart DDDDD.

* * * * *

(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) and table 6 to subpart DDDDD.

* * * * *

(35) 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 1 to subpart DDDDD of this part, table 2 to subpart DDDDD of this part, table 5 to subpart DDDDD, table 11 to subpart DDDDD of this part, table 12 to subpart DDDDD of this part, table 13 to subpart DDDDD of this part, and table 4 to subpart JJJJJJ of this part.

* * * * *

(40) ASTM D396–10 Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for § 63.7575 and § 6311237.

* * * * *

(46) ASTM D4606–03(2007), Standard Test Method for Determination of Arsenic and Selenium in Coal by the Hydride Generation/Atomic Absorption Method, approved October 1, 2007, IBR approved for table 6 to subpart DDDDD.

* * * * *

(55) ASTM D6357–11, Test Methods for Determination of Trace Elements in Coal, Coke, and Combustion Residues from Coal Utilization Processes by Inductively Coupled Plasma Atomic Emission Spectrometry, approved April 1, 2011, IBR approved for table 6 to subpart DDDDD.

* * * * *

(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) and table 6 to subpart DDDDD.

(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) and table 6 to subpart DDDDD.

* * * * *

(76) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, approved July 15, 2011, IBR approved for § 63.7575 and § 63.11237.

(77) ASTM D975–11b, Standard Specification for Diesel Fuel Oils, approved December 1, 2011, IBR approved for § 63.7575.

(78) ASTM D5864–11 Standard Test Method for Determining Aerobic Aquatic Biodegradation of Lubricants or Their Components, approved March 1, 2011, IBR approved for table 6 to subpart DDDDD.

(79) ASTM D240–09 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, approved July 1, 2009, IBR approved for table 6 to subpart DDDDD.

(80) ASTM D4208–02(2007) Standard Test Method for Total Chlorine in Coal by the Oxygen Bomb Combustion/Ion Selective Electrode Method, approved May 1, 2007, IBR approved for table 6 to subpart DDDDD.

(81) ASTM D5192–09 Standard Practice for Collection of Coal Samples from Core, approved June 1, 2009, IBR approved for table 6 to subpart DDDDD.

(82) ASTM D7430–11ae1, Standard Practice for Mechanical Sampling of Coal, approved October 1, 2011, IBR approved for table 6 to subpart DDDDD.

(83) ASTM D6883–04, Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles, approved June 1, 2004, IBR approved for table 6 to subpart DDDDD.

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(p) * * *

(12) Method 5050 (SW–846–5050), Bomb Preparation Method for Solid Waste, Revision 0, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition IBR approved for table 6 to subpart DDDDD.

(13) Method 9056 (SW–846–9056), Determination of Inorganic Anions by Ion Chromatography, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(14) Method 9076 (SW–846–9076), Test Method for Total Chlorine in New and Used Petroleum Products by Oxidative Combustion and Microcoulometry, Revision 0, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(15) Method 1631 Revision E, Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Absorption Fluorescence Spectrometry, Revision E, EPA–821–R–02–019, August 2002, IBR approved for table 6 to subpart DDDDD.

(16) Method 200.8, Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma—Mass Spectrometry, Revision 5.4, 1994, IBR approved for table 6 to subpart DDDDD.

(17) Method 6020A (SW–846–6020A), Inductively Coupled Plasma-Mass Spectrometry, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,

Third Edition, IBR approved for table 6 to subpart DDDDD.

(18) Method 6010C (SW–846–6010C), Inductively Coupled Plasma-Atomic Emission Spectrometry, Revision 3, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(19) Method 7060A (SW–846–7060A), Arsenic (Atomic Absorption, Furnace Technique), Revision 1, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(20) Method 7740 (SW–846–7740), Selenium (Atomic Absorption, Furnace Technique), Revision 0, September 1986, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

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(r) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332–8686, *http://www.tappi.org.*

(1) TAPPI T 266, Determination of Sodium, Calcium, Copper, Iron, and Manganese in Pulp and Paper by Atomic Absorption Spectroscopy (Reaffirmation of T 266 om-02), Draft No. 2, July 2006, IBR approved for table 6 to subpart DDDDD.

(2) [Reserved]

Subpart JJJJJJ—[AMENDED]

■ 3. Section 63.11194 is amended by revising paragraphs (a)(1), (c) and (d), by redesignating paragraph (e) as paragraph (f) and by adding new paragraph (e) to read as follows:

§ 63.11194 What is the affected source of this subpart?

(a) * * *

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers within a subcategory, as listed in § 63.11200 and defined in § 63.11237, located at an area source.

* * * * *

(c) An affected source is a new source if you commenced construction of the affected source after June 4, 2010, and the boiler meets the applicability criteria at the time you commence construction.

(d) An affected source is a reconstructed source if the boiler meets the reconstruction criteria as defined in § 63.2, you commenced reconstruction after June 4, 2010, and the boiler meets the applicability criteria at the time you commence reconstruction.

(e) An existing dual-fuel fired boiler meeting the definition of gas-fired boiler, as defined in § 63.11237, that meets the applicability requirements of this subpart after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel.

* * * * *

■ 4. Section 63.11195 is amended by revising the introductory text and paragraphs (c) and (g) and by adding paragraphs (h) through (k) to read as follows:

§ 63.11195 Are any boilers not subject to this subpart?

The types of boilers listed in paragraphs (a) through (k) of this section are not subject to this subpart and to any requirements in this subpart.

* * * * *

(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers), unless such units do not combust hazardous waste and combust comparable fuels.

* * * * *

(g) Any boiler that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler is provided by regulated gas streams that are subject to another standard.

(h) Temporary boilers as defined in this subpart.

(i) Residential boilers as defined in this subpart.

(j) Electric boilers as defined in this subpart.

(k) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

■ 5. Section 63.11196 is amended by revising paragraphs (a)(1) and (d) to read as follows:

§ 63.11196 What are my compliance dates?

(a) * * *

(1) If the existing affected boiler is subject to a work practice or management practice standard of a tune-up, you must achieve compliance with the work practice or management practice standard no later than March 21, 2014.

* * * * *

(d) If you own or operate an industrial, commercial, or institutional boiler and would be subject to this subpart except for the exemption in § 63.11195(b) for commercial and industrial solid waste incineration units covered by 40 CFR part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the waste to fuel switch as specified in § 60.2145(a)(2) and (3) of subpart CCCC or § 60.2710(a)(2) and (3) of subpart DDDD.

■ 6. Section 63.11200 is revised to read as follows:

§ 63.11200 What are the subcategories of boilers?

The subcategories of boilers, as defined in § 63.11237 are:

(a) Coal.

(b) Biomass.

(c) Oil.

(d) Seasonal boilers.

(e) Oil-fired boilers with heat input capacity of equal to or less than 5 million British thermal units (Btu) per hour.

(f) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.

(g) Limited-use boilers.

■ 7. Section 63.11201 is amended by revising paragraphs (b) and (d) to read as follows:

§ 63.11201 What standards must I meet?

* * * * *

(b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets or is amended to meet the energy assessment requirements in Table 2 to this subpart satisfies the energy assessment requirement. A facility that operates under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected units, also satisfies the energy assessment requirement.

* * * * *

(d) These standards apply at all times the affected boiler is operating, except during periods of startup and shutdown as defined in § 63.11237, during which time you must comply only with Table 2 to this subpart.

■ 8. Section 63.11205 is amended by revising paragraphs (b), (c) introductory

text, (c)(1) introductory text, and (c)(1)(i) to read as follows:

§ 63.11205 What are my general requirements for complying with this subpart?

* * * * *

(b) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or a continuous monitoring system (CMS), including a continuous emission monitoring system (CEMS), a continuous opacity monitoring system (COMS), or a continuous parameter monitoring system (CPMS), where applicable. You may demonstrate compliance with the applicable mercury emission limit using fuel analysis if the emission rate calculated according to § 63.11211(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing.

(c) If you demonstrate compliance with any applicable emission limit through performance stack testing and subsequent compliance with operating limits (including the use of CPMS), with a CEMS, or with a COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (3) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (vi) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.11224.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

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■ 9. Section 63.11210 is amended by revising paragraphs (b) through (e) and adding paragraphs (f) through (j) to read as follows:

§ 63.11210 What are my initial compliance requirements and by what date must I conduct them?

* * * * *

(b) For existing affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2), except as provided in paragraph (j) of this section.

(c) For existing affected boilers that have applicable work practice standards, management practices, or emission reduction measures, you must demonstrate initial compliance no later than the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2), except as provided in paragraph (j) of this section.

(d) For new or reconstructed affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after March 21, 2011 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(e) For new or reconstructed oil-fired boilers that combust 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 emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce particulate matter (PM) or sulfur dioxide emissions, you are not subject to the PM emission limit in Table 1 of this subpart providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a new type of fuel or fuel mixture that does not meet the requirements of this paragraph, you must conduct a performance test within 60 days of burning the new fuel.

(f) For new or reconstructed affected boilers that have applicable work practice standards or management practices, you are not required to complete an initial performance tune-up, but you are required to complete the applicable biennial or 5-year tune-up as specified in § 63.11223 no later than 25 months or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(g) For affected boilers that ceased burning solid waste consistent with § 63.11196(d) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch as specified in § 60.2145(a)(2) and (3) of subpart CCCC or § 60.2710(a)(2) and (3) of subpart DDDD. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(h) For affected boilers that switch fuels or make a physical change to the boiler that results in the applicability of a different subcategory within subpart JJJJJJ or the boiler becoming subject to subpart JJJJJJ, you must demonstrate compliance within 180 days of the effective date of the fuel switch or the physical change. Notification of such changes must be submitted according to § 63.11225(g).

(i) For boilers located at existing major sources of HAP that limit their potential to emit (e.g., make a physical change or take a permit limit) such that the existing major source becomes an area source, you must comply with the applicable provisions as specified in paragraphs (i)(1) through (3) of this section.

(1) Any such existing boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2014 or upon the existing major source commencing operation as an area source.

(2) Any new or reconstructed boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2011 or startup.

(3) Notification of such changes must be submitted according to § 63.11225(g).

(j) For existing affected boilers that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.11196, you must comply with the applicable provisions as specified in paragraphs (j)(1) through (3) of this section.

(1) You must complete the initial compliance demonstration, if subject to the emission limits in Table 1 to this subpart, as specified in paragraphs (a) and (b) of this section, no later than 180 days after the re-start of the affected boiler and according to the applicable provisions in § 63.7(a)(2).

(2) You must complete the initial performance tune-up, if subject to the tune-up requirements in § 63.11223, by following the procedures described in § 63.11223(b) no later than 30 days after the re-start of the affected boiler.

(3) You must complete the one-time energy assessment, if subject to the energy assessment requirements specified in Table 2 to this subpart, no

later than the compliance date specified in § 63.11196.

■ 10. Section 63.11211 is amended by revising paragraphs (a), (b)(1), and (b)(2) to read as follows:

§ 63.11211 How do I demonstrate initial compliance with the emission limits?

(a) For affected boilers that demonstrate compliance with any of the emission limits of this subpart through performance (stack) testing, your initial compliance requirements include conducting performance tests according to § 63.11212 and Table 4 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler according to § 63.11213 and Table 5 to this subpart, establishing operating limits according to § 63.11222, Table 6 to this subpart and paragraph (b) of this section, as applicable, and conducting CMS performance evaluations according to § 63.11224. For affected boilers that burn a single type of fuel, you are exempted from the compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler. For purposes of this subpart, boilers that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected boilers that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.11213 and Table 5 to this subpart.

(b) * * *

(1) For a wet scrubber, you must establish the minimum scrubber liquid flow rate and minimum scrubber pressure drop as defined in § 63.11237, as your operating limits during the three-run performance stack test. If you use a wet scrubber and you conduct separate performance stack tests for PM and mercury emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. If you conduct multiple performance stack tests, you must set the minimum scrubber liquid flow rate and pressure drop operating limits at the highest minimum values established during the performance stack tests.

(2) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum total secondary electric power (secondary voltage and secondary current), as defined in § 63.11237, as your operating limits during the three-run performance stack test.

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■ 11. Section 63.11212 is amended by revising paragraphs (b) and (e) to read as follows:

§ 63.11212 What stack tests and procedures must I use for the performance tests?

* * * * *

(b) You must conduct each stack test according to the requirements in Table 4 to this subpart. Boilers that use a CEMS for carbon monoxide (CO) are exempt from the initial CO performance testing in Table 4 to this subpart and the oxygen concentration operating limit requirement specified in Table 3 to this subpart.

* * * * *

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A–7 to part 60 of this chapter to convert the measured PM concentrations and the measured mercury concentrations that result from the performance test to pounds per million Btu heat input emission rates.

■ 12. Section 63.11214 is amended by revising paragraph (c) to read as follows:

§ 63.11214 How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?

* * * * *

(c) If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed according to Table 2 to this subpart and is an accurate depiction of your facility.

* * * * *

■ 13. Section 63.11220 is revised to read as follows:

§ 63.11220 When must I conduct subsequent performance tests or fuel analyses?

(a) If your boiler has a heat input capacity of 10 million British thermal units per hour or greater, you must conduct all applicable performance (stack) tests according to § 63.11212 on a triennial basis, except as specified in paragraphs (b) through (d) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test.

(b) When demonstrating initial compliance with the PM emission limit, if your boiler's performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you do not need to conduct further performance tests for PM but must continue to comply with all applicable operating limits and monitoring requirements. If your initial performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests as specified in paragraph (a) of this section.

(c) If you demonstrate compliance with the mercury emission limit based on fuel analysis, you must conduct a fuel analysis according to § 63.11213 for each type of fuel burned as specified in paragraphs (c)(1) and (2) of this section. If you plan to burn a new type of fuel or fuel mixture, you must conduct a fuel analysis before burning the new type of fuel or mixture in your boiler. You must recalculate the mercury emission rate using Equation 1 of § 63.11211. The recalculated mercury emission rate must be less than the applicable emission limit.

(1) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are measured to be equal to or less than half of the mercury emission limit, you do not need to conduct further fuel analysis sampling but must continue to comply with all applicable operating limits and monitoring requirements.

(2) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are greater than half of the mercury emission limit, you must conduct quarterly sampling.

(d) For existing affected boilers that have not operated since the previous compliance demonstration and more than 3 years have passed since the previous compliance demonstration, you must complete your subsequent compliance demonstration no later than 180 days after the re-start of the affected boiler.

■ 14. Section 63.11221 is revised to read as follows:

§ 63.11221 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.11205(c).

(b) You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating and compliance is required, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks, required zero and span

adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data collected during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or quality control activities in calculations used to report emissions or operating levels. Any such periods must be reported according to the requirements in § 63.11225. 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, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan), failure to collect required data is a deviation of the monitoring requirements.

■ 15. Section 63.11223 is amended by revising paragraphs (a), (b) introductory text, (b)(1), (b)(3) through (5), (b)(6) introductory text, (b)(6)(i), (b)(6)(iii), (b)(7), and (c), and adding paragraphs (d) through (g) to read as follows:

§ 63.11223 How do I demonstrate continuous compliance with the work practice and management practice standards?

(a) For affected sources subject to the work practice standard or the management practices of a tune-up, you must conduct a performance tune-up according to paragraph (b) of this section and keep records as required in § 63.11225(c) to demonstrate continuous compliance. You must conduct the tune-up while burning the type of fuel (or fuels in the case of boilers that routinely burn two types of fuels at the same time) that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.

(b) Except as specified in paragraphs (c) through (f) of this section, you must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in paragraphs (b)(1) through (7) of this section. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up. For a new or reconstructed boiler, the first biennial tune-up must be no later than 25 months after the initial startup of the new or reconstructed boiler.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection.

* * * * *

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection.

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject.

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the 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). Measurements may be taken using a portable CO analyzer.

(6) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler.

* * * * *

(iii) The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.

(7) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.

(c) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up must conduct a tune-up of the boiler every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed boiler with an oxygen trim system, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(d) Seasonal boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed seasonal boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Seasonal boilers are not subject to the emission limits in Table 1 to this subpart or the operating limits in Table 3 to this subpart.

(e) Oil-fired boilers with a heat input capacity of equal to or less than 5 million Btu per hour must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed oil-fired boiler with a heat input capacity of equal to or less than 5 million Btu per hour, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified

in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(f) Limited-use boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed limited-use boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Limited-use boilers are not subject to the emission limits in Table 1 to this subpart, the energy assessment requirements in Table 2 to this subpart, or the operating limits in Table 3 to this subpart.

(g) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. 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 or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

■ 16. Section 63.11224 is amended by:
■ a. Revising paragraphs (a) introductory text, (a)(1) through (3), (a)(5), (a)(6),
■ b. Adding paragraph (a)(7).
■ c. Revising paragraphs (c)(1) introductory text, (c)(2) introductory text, and (d).
■ d. Revising paragraphs (e) introductory text, (e)(6), and (e)(7).
■ e. Adding paragraph (e)(8).
■ f. Revising paragraph (f)(7).

The revisions and additions read as follows:

§ 63.11224 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler is subject to a CO emission limit in Table 1 to this subpart, you must either install, operate, and maintain a CEMS for CO and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section, or install, calibrate, operate, and maintain an oxygen analyzer system, as defined in § 63.11237, according to the manufacturer's recommendations and paragraphs (a)(7) and (d) of this section, as applicable, by the compliance date specified in § 63.11196. Where a certified CO CEMS is used, the CO level shall be monitored at the outlet of the boiler, after any add-on controls or flue gas recirculation system and before release to the atmosphere. Boilers that use a CO CEMS are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in § 63.11211(a) of this subpart. Oxygen monitors and oxygen trim systems must be installed to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location.

(1) Each CO CEMS must be installed, operated, and maintained according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, and each oxygen CEMS must be installed, operated, and maintained according to Performance Specification 3 at 40 CFR part 60, appendix B. Both the CO and oxygen CEMS must also be installed, operated, and maintained according to the site-specific monitoring plan developed according to paragraph (c) of this section.

(2) You must conduct a performance evaluation of each CEMS according to the requirements in § 63.8(e) and according to Performance Specifications 3 and 4, 4A, or 4B at 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) every 15 minutes. You must have CEMS data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

* * * * *

(5) You must calculate hourly averages, corrected to 3 percent oxygen, from each hour of CO CEMS data in parts per million CO concentrations and determine the 10-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 10-day rolling average from all of the hourly averages collected for the 10-day operating period using Equation 2 of this section.

$$\text{10-day average} = \frac{\Sigma_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 2)}$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 10 boiler operating days

(6) For purposes of collecting CO data, you must operate the CO CEMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(7) You must operate the oxygen analyzer system at or above the minimum oxygen level that is established as the operating limit according to Table 6 to this subpart when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. Operation of oxygen trim systems to meet these requirements shall not be done in a manner which compromises furnace safety.

* * * * *

(c) * * *

(1) For each CMS required in this section, you must develop, and submit to the EPA Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan (if requested) at least 60 days before your initial performance evaluation of your CMS.

* * * * *

(2) In your site-specific monitoring plan, you must also address paragraphs (c)(2)(i) through (iii) of this section.

* * * * *

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each CPMS according to the procedures in paragraphs (d)(1) through (4) of this section.

(1) The CPMS must complete a minimum of one cycle of operation every 15 minutes. You must have data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(2) You must calculate hourly arithmetic averages from each hour of CPMS data in units of the operating limit and determine the 30-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 30-day rolling average from all of the hourly averages collected for the 30-day operating period using Equation 3 of this section.

$$\text{30-day average} = \frac{\Sigma_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 3)}$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 30 boiler operating days

(3) For purposes of collecting data, you must operate the CPMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CPMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(4) Record the results of each inspection, calibration, and validation check.

(e) If you have an applicable opacity operating limit under this rule, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (e)(1) through (8) of this section by the compliance date specified in § 63.11196.

* * * * *

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) You must calculate and record 6-minute averages from the opacity monitoring data and determine and record the daily block average of recorded readings, except as provided in § 63.11221(c).

(8) For purposes of collecting opacity data, you must operate the COMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when COMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(f) * * *

(7) For positive pressure fabric filter systems that do not duct all compartments or cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

* * * * *

■ 17. Section 63.11225 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(1), (a)(2), (a)(4), (a)(5), (b) introductory text, (b)(2), (c) introductory text, (c)(2) introductory text, and (c)(2)(ii).

■ b. Adding paragraphs (c)(2)(iii) through (vi).

■ c. Revising paragraphs (d), (e), and (g).

The revisions and additions read as follows:

§ 63.11225 What are my notification, reporting, and recordkeeping, requirements?

(a) You must submit the notifications specified in paragraphs (a)(1) through (5) of this section to the administrator.

(1) You must submit all of the notifications in §§ 63.7(b); 63.8(e) and (f); and 63.9(b) through (e), (g), and (h) that apply to you by the dates specified in those sections except as specified in paragraphs (a)(2) and (4) of this section.

(2) An Initial Notification must be submitted no later than January 20, 2014 or within 120 days after the source becomes subject to the standard.

* * * * *

(4) You must submit the Notification of Compliance Status no later than 120 days after the applicable compliance date specified in § 63.11196 unless you must conduct a performance stack test. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of completing the performance stack test. You must submit the Notification of Compliance Status in accordance with paragraphs (a)(4)(i) and (vi) of this section. The Notification of Compliance Status must include the information and certification(s) of compliance in paragraphs (a)(4)(i) through (v) of this section, as applicable, and signed by a responsible official.

(i) You must submit the information required in § 63.9(h)(2), except the information listed in § 63.9(h)(2)(i)(B), (D), (E), and (F). If you conduct any performance tests or CMS performance evaluations, you must submit that data as specified in paragraph (e) of this section. If you conduct any opacity or visible emission observations, or other monitoring procedures or methods, you must submit that data to the Administrator at the appropriate address listed in § 63.13.

(ii) "This facility complies with the requirements in § 63.11214 to conduct an initial tune-up of the boiler."

(iii) "This facility has had an energy assessment performed according to § 63.11214(c)."

(iv) For units that install bag leak detection systems: "This facility complies with the requirements in § 63.11224(f)."

(v) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."

(vi) The notification must be submitted electronically using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written Notification of Compliance Status must be submitted to the

Administrator at the appropriate address listed in § 63.13.

(5) If you are using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, you must include in the Notification of Compliance Status the date of the test and a summary of the results, not a complete test report, relative to this subpart.

(b) You must prepare, by March 1 of each year, and submit to the delegated authority upon request, an annual compliance certification report for the previous calendar year containing the information specified in paragraphs (b)(1) through (4) of this section. You must submit the report by March 15 if you had any instance described by paragraph (b)(3) of this section. For boilers that are subject only to a requirement to conduct a biennial or 5-year tune-up according to § 63.11223(a) and not subject to emission limits or operating limits, you may prepare only a biennial or 5-year compliance report as specified in paragraphs (b)(1) and (2) of this section.

* * * * *

(2) Statement by a responsible official, with the official's name, title, phone number, email address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart. Your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) ''This facility complies with the requirements in § 63.11223 to conduct a biennial or 5-year tune-up, as applicable, of each boiler.''

(ii) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: ''No secondary materials that are solid waste were combusted in any affected unit.''

(iii) ''This facility complies with the requirement in §§ 63.11214(d) and 63.11223(g) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.''

* * * * *

(c) You must maintain the records specified in paragraphs (c)(1) through (7) of this section.

* * * * *

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by § 63.11214 and § 63.11223 as specified in paragraphs (c)(2)(i) through (vi) of this section.

* * * * *

(ii) For operating units that combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) of this chapter, you must keep a record which documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1). If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfies the definition of processing in § 241.2 and each of the legitimacy criteria in § 241.3(d)(1) of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4, you must keep records documenting that the material is a listed non-waste under § 241.4(a).

(iii) For each boiler required to conduct an energy assessment, you must keep a copy of the energy assessment report.

(iv) For each boiler subject to an emission limit in Table 1 to this subpart, you must also keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used.

(v) For each boiler that meets the definition of seasonal boiler, you must keep records of days of operation per year.

(vi) For each boiler that meets the definition of limited-use boiler, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and records of fuel use for the days the boiler is operating.

* * * * *

(d) Your records must be in a form suitable and readily available for expeditious review. You must keep each record for 5 years following the date of each recorded action. You must keep each record on-site or be accessible from a central location by computer or other means that instantly provide access at the site for at least 2 years after the date of each recorded action. You may keep the records off site for the remaining 3 years.

(e)(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including CBI, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation test as defined in § 63.2, you must submit relative accuracy test audit (RATA) data to EPA's CDX by using CEDRI in accordance with paragraph (e)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator at the appropriate address listed in § 63.13.

* * * * *

(g) If you have switched fuels or made a physical change to the boiler and the fuel switch or change resulted in the

applicability of a different subcategory within subpart JJJJJJ, in the boiler becoming subject to subpart JJJJJJ, or in the boiler switching out of subpart JJJJJJ due to a change to 100 percent natural gas, or you have taken a permit limit that resulted in you being subject to subpart JJJJJJ, you must provide notice of the date upon which you switched fuels, made the physical change, or took a permit limit within 30 days of the change. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that have switched fuels, were physically changed, or took a permit limit, and the date of the notice.

(2) The date upon which the fuel switch, physical change, or permit limit occurred.

18. Section 63.11226 is revised to read as follows:

§ 63.11226 Affirmative defense for violation of emission standards during malfunction.

In response to an action to enforce the standards set forth in § 63.11201 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

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

(1) The violation:

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

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

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

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

(2) Repairs were made as expeditiously as possible when a violation occurred; and

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

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

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

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

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

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

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

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

■ 19. Section 63.11236 is amended by revising paragraph (a) to read as follows:

§ 63.11236 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by EPA or an administrator 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 has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to your state, local, or tribal agency.

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■ 20. Section 63.11237 is amended as follows:

■ a. By adding definitions in alphabetical order for "10-day rolling average," "30-day rolling average," "Annual heat input," "Biodiesel," "Calendar year," "Common stack," "Daily block average," "Distillate oil," "Electric boiler," "Electric utility steam generating unit (EGU)," "Energy management program," "Fluidized bed boiler," "Fluidized bed combustion," "Hourly average," "Limited-use boiler," "Load fraction," "Minimum scrubber pressure drop," "Minimum sorbent injection rate," "Minimum total secondary electric power," "Operating day," "Oxygen analyzer system," "Oxygen trim system," "Process heater," "Regulated gas stream," "Residential boiler," "Residual oil," "Seasonal boiler," "Shutdown," "Solid fuel," "Startup," "Temporary boiler," "Tune-up," "Vegetable oil," "Voluntary Consensus Standards (VCS)," and "Wet scrubber."

■ b. By revising the definitions for "Bag leak detection system," "Biomass subcategory," "Boiler," "Boiler system," "Deviation," "Dry scrubber," "Electrostatic precipitator (ESP)," "Energy assessment," "Energy use system," "Federally enforceable," "Gas-fired boiler," "Heat input," "Hot water heater," "Institutional boiler," "Liquid fuel," "Minimum activated carbon injection rate," "Minimum oxygen level," "Minimum scrubber liquid flow rate," "Natural gas," "Oil subcategory," "Particulate matter," "Period of gas curtailment or supply interruption," "Qualified Energy Assessor," "Solid fossil fuel," and "Waste heat boiler."

■ c. By removing the definitions for "Annual heat input basis," "Minimum PM scrubber pressure drop," "Minimum sorbent flow rate," and "Minimum voltage or amperage".

§ 63.11237 What definitions apply to this subpart?

10-day rolling average means the arithmetic mean of all valid hours of data from 10 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

30-day rolling average means the arithmetic mean of all valid hours of data from 30 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

* * * * *

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.,* baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

* * * * *

Biomass subcategory includes any boiler that burns any biomass and is not in the coal subcategory.

Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of *Boiler*.

Boiler system means the boiler and associated components, such as, feedwater systems, combustion air systems, fuel systems (including burners), blowdown systems, combustion control systems, steam systems, and condensate return systems, directly connected to and serving the energy use systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

* * * * *

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown and periods when the unit is not operating.

Deviation (1) 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 applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; 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.

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 § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751–11b (incorporated by reference, see § 63.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Electric boiler means a boiler in which electric heating serves as the source of heat. Electric boilers that burn gaseous or liquid fuel during periods of electrical power curtailment or failure are included in this definition.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts 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 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be ''capable of combusting'' fossil fuels, an EGU would need to have these fuels allowed in their operating permits 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 EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2015.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers with less than 0.3 trillion Btu per year (TBtu/year) heat input capacity will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (*e.g.,* steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour energy assessment.

(2) The energy assessment for facilities with affected boilers with 0.3 to 1.0 TBtu/year heat input capacity will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the affected boiler(s) energy (*e.g.,* steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour energy assessment.

(3) The energy assessment for facilities with affected boilers with greater than 1.0 TBtu/year heat input capacity will be up to 24 on-site technical labor hours in length for the first TBtu/year plus 8 on-site technical labor hours for every additional 1.0 TBtu/year not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler

system(s) and any on-site energy use system(s) accounting for at least 20 percent of the affected boiler(s) energy (*e.g.,* steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use system(s) serving as the basis for the percent of affected boiler(s) energy production, as applicable, in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (*e.g.,* product X manufacturing area; product Y drying area; Building Z).

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system (1) Includes the following systems located on the site of the affected boiler that use energy provided by the boiler:

(i) Process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot water systems; building envelop; and lighting; or

(ii) Other systems that use steam, hot water, process heat, or electricity, provided by the affected boiler.

(2) Energy use systems are only those systems using energy clearly produced by affected boilers.

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Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, 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.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

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 forward flow of air and combustion products.

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Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Heat input means heat derived from combustion of fuel in a boiler and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass fuel and hot water is withdrawn for use external to the vessel. Hot water boilers (*i.e.,* not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 million Btu per hour heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on-demand hot water.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

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Institutional boiler means a boiler used in institutional establishments such as, but not limited to, medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, and governmental buildings to provide electricity, steam, and/or hot water.

Limited-use boiler means any boiler that burns any amount of solid or liquid fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil meeting the specification in 40 CFR 279.11, liquid biofuels, biodiesel, and vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (*e.g.,* for 50 percent load the load fraction is 0.5).

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable carbon monoxide emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average scrubber liquid flow rate (*e.g.,* to the particulate matter scrubber) measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath

the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions (*i.e.,* a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals). Additionally, natural gas must either be composed of at least 70 percent methane by volume or have 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); or

(4) Propane or propane-derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Oil subcategory includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories. Gas-fired boilers that burn liquid fuel only during periods of gas curtailment, gas supply interruptions, startups, or for periodic testing are not included in this definition. Periodic testing on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

* * * * *

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 boiler unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location. This definition includes oxygen trim systems.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

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Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vii) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Regulated gas stream means an offgas stream that is routed to a boiler for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (*e.g.,* university campus, military base, church grounds) or commercial/industrial facility (*e.g.,* farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families, or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396–10 (incorporated by reference, see § 63.14(b)).

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Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire-derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means either the first-ever firing of fuel in a boiler for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose.

Temporary boiler means any gaseous or liquid fuel boiler 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 boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.

(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 within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Tune-up means adjustments made to a boiler in accordance with the procedures outlined in § 63.11223(b).

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards (VCS) mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, *http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800–463–6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B–1000 Brussels, Belgium +32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214–230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: the United 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 their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (*i.e.,* hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (*e.g.,* thermal oxidizer, kiln, furnace) or power (*e.g.,* combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

* * * * *

■ 21. Table 1 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11201, you must comply with the following applicable emission limits:

TABLE 1 TO SUBPART JJJJJJ OF PART 63—EMISSION LIMITS

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
1. New coal-fired boilers with heat input capacity of 30 million British thermal units per hour (MMBtu/hr) or greater that do not meet the definition of limited-use boiler.	a. PM (Filterable)	3.0E–02 pounds(lb) per million British thermal units (MMBtu) of heat input.
	b. Mercury	2.2E–05 lb per MMBtu of heat input.
	c. CO	420 parts per million (ppm) by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).
2. New coal-fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of limited-use boiler.	a. PM (Filterable)	4.2E–01 lb per MMBtu of heat input.
	b. Mercury	2.2E–05 lb per MMBtu of heat input.
	c. CO	420 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).

TABLE 1 TO SUBPART JJJJJJ OF PART 63—EMISSION LIMITS—Continued

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
3. New biomass-fired boilers with heat input capacity of 30 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler.	PM (Filterable)	3.0E–02 lb per MMBtu of heat input.
4. New biomass fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler.	PM (Filterable)	7.0E–02 lb per MMBtu of heat input.
5. New oil-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler.	PM (Filterable)	3.0E–02 lb per MMBtu of heat input.
6. Existing coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of limited-use boiler.	a. Mercury b. CO	2.2E–05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen.

■ 22. Table 2 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11201, you must comply with the following applicable work practice standards, emission reduction measures, and management practices:

TABLE 2 TO SUBPART JJJJJJ OF PART 63—WORK PRACTICE STANDARDS, EMISSION REDUCTION MEASURES, AND MANAGEMENT PRACTICES

If your boiler is in this subcategory . . .	You must meet the following . . .
1. Existing or new coal-fired, new biomass-fired, or new oil-fired boilers (units with heat input capacity of 10 MMBtu/hr or greater).	Minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.
2. Existing coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
3. New coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
4. Existing oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
5. New oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
6. Existing biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
7. New biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
8. Existing seasonal boilers	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
9. New seasonal boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
10. Existing limited-use boilers	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
11. New limited-use boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
12. Existing oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
13. New oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr.	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.

TABLE 2 TO SUBPART JJJJJJ OF PART 63—WORK PRACTICE STANDARDS, EMISSION REDUCTION MEASURES, AND MANAGEMENT PRACTICES—Continued

If your boiler is in this subcategory . . .	You must meet the following . . .
14. Existing coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
15. New coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
16. Existing coal-fired, biomass-fired, or oil-fired boilers (units with heat input capacity of 10 MMBtu/hr and greater), not including limited-use boilers.	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table satisfies the energy assessment requirement. Energy assessor approval and qualification requirements are waived in instances where past or amended energy assessments are used to meet the energy assessment requirements. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items (1) to (4) appropriate for the on-site technical hours listed in § 63.11237: (1) A visual inspection of the boiler system, (2) An evaluation of operating characteristics of the affected boiler systems, specifications of energy use systems, operating and maintenance procedures, and unusual operating constraints, (3) An inventory of major energy use systems consuming energy from affected boiler(s) and which are under control of the boiler owner or operator, (4) A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage, (5) A list of major energy conservation measures that are within the facility's control, (6) A list of the energy savings potential of the energy conservation measures identified, and (7) A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

■ 23. Table 3 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11201, you must comply with the applicable operating limits:

TABLE 3 TO SUBPART JJJJJJ OF PART 63—OPERATING LIMITS FOR BOILERS WITH EMISSION LIMITS

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits except during periods of startup and shutdown . . .
1. Fabric filter control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Install and operate a bag leak detection system according to § 63.11224 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Maintain the 30-day rolling average total secondary electric power of the electrostatic precipitator at or above the minimum total secondary electric power as defined in § 63.11237.
3. Wet scrubber control	Maintain the 30-day rolling average pressure drop across the wet scrubber at or above the minimum scrubber pressure drop as defined in § 63.11237 and the 30-day rolling average liquid flow rate at or above the minimum scrubber liquid flow rate as defined in § 63.11237.
4. Dry sorbent or activated carbon injection control.	Maintain the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent injection rate or minimum activated carbon injection rate as defined in § 63.11237. When your boiler operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (*e.g.,* actual heat input divided by the heat input during the performance stack test; for 50 percent load, multiply the injection rate operating limit by 0.5).
5. Any other add-on air pollution control type.	This option is for boilers that operate dry control systems. Boilers must maintain opacity to less than or equal to 10 percent opacity (daily block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rate calculated according to § 63.11211(c) are less than the applicable emission limit for mercury.
7. Performance stack testing	For boilers that demonstrate compliance with a performance stack test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance stack test.
8. Oxygen analyzer system	For boilers subject to a CO emission limit that demonstrate compliance with an oxygen analyzer system as specified in § 63.11224(a), maintain the 30-day rolling average oxygen level at or above the minimum oxygen level as defined in § 63.11237. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.11224(a)(7).

* * * * *

■ 24. Table 6 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11211, you must comply with the following requirements for establishing operating limits:

TABLE 6 TO SUBPART JJJJJJ OF PART 63—ESTABLISHING OPERATING LIMITS

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM or mercury ..	a. Wet scrubber operating parameters.	Establish site-specific minimum scrubber pressure drop and minimum scrubber liquid flow rate operating limits according to § 63.11211(b).	Data from the pressure drop and liquid flow rate monitors and the PM or mercury performance stack tests.	(a) You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average pressure drop and liquid flow rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters.	Establish a site-specific minimum total secondary electric power operating limit according to § 63.11211(b).	Data from the secondary electric power monitors and the PM or mercury performance stack tests.	(a) You must collect secondary electric power data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average total secondary electric power for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
2. Mercury	Dry sorbent or activated carbon injection rate operating parameters.	Establish a site-specific minimum sorbent or activated carbon injection rate operating limit according to § 63.11211(b).	Data from the sorbent or activated carbon injection rate monitors and the mercury performance stack tests.	(a) You must collect sorbent or activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average sorbent or activated carbon injection rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run. (c) When your unit operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance stack test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. CO	Oxygen	Establish a unit-specific limit for minimum oxygen level.	Data from the oxygen analyzer system specified in § 63.11224(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average hourly oxygen concentration for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
4. Any pollutant for which compliance is demonstrated by a performance stack test.	Boiler operating load.	Establish a unit-specific limit for maximum operating load according to § 63.11212(c).	Data from the operating load monitors (fuel feed monitors or steam generation monitors).	(a) You must collect operating load data (fuel feed rate or steam generation data) every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

■ 25. Table 7 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11222, you must show continuous compliance with the emission limitations for each boiler according to the following:

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

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.11224(e) and § 63.11221; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.11224(f) and operating the fabric filter such that the requirements in § 63.11222(a)(4) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow Rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pressure drop and liquid flow rate at or above the minimum pressure drop and minimum liquid flow rate according to § 63.11211.
4. Dry Scrubber Sorbent or Activated Carbon Injection Rate.	a. Collecting the sorbent or activated carbon injection rate monitoring system data for the dry scrubber according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent or activated carbon injection rate according to § 63.11211.
5. Electrostatic Precipitator Total Secondary Electric Power.	a. Collecting the total secondary electric power monitoring system data for the electrostatic precipitator according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power at or above the minimum total secondary electric power according to § 63.11211.
6. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.11213 as applicable; and b. Keeping monthly records of fuel use according to §§ 63.11222(a)(2) and 63.11225(b)(4).
7. Oxygen content	a. Continuously monitoring the oxygen content of flue gas according to § 63.11224 (This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.11224(a)(7)); and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average oxygen content at or above the minimum oxygen level established during the most recent CO performance test.
8. CO emissions	a. Continuously monitoring the CO concentration in the combustion exhaust according to §§ 63.11224 and 63.11221; and b. Correcting the data to 3 percent oxygen, and reducing the data to 1-hour averages; and c. Reducing the data from the hourly averages to 10-day rolling averages; and d. Maintaining the 10-day rolling average CO concentration at or below the applicable emission limit in Table 1 to this subpart.
9. Boiler operating load	a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to § 63.11212(c) and Table 6 to this subpart.

■ 26. Table 8 to subpart JJJJJJ is amended by:

■ a. Revising the entry for ''§ 63.9''.

■ b. Revising the entry for ''§ 63.10(e) and (f)''.

■ c. Adding an entry for ''§ 63.10(f)''.

The revisions read as follows:

* * * * *

TABLE 8 TO SUBPART JJJJJJ OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJJJ

General provisions cite	Subject	Does it apply?
*	* * *	* * *
§ 63.9	Notification Requirements	Yes, excluding the information required in § 63.9(h)(2)(i)(B), (D), (E) and (F). See § 63.11225.
*	* * *	* * *
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
*	* * *	* * *

[FR Doc. 2012–31645 Filed 1–31–13; 8:45 am]

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Part II

Environmental Protection Agency

40 CFR Parts 60 and 63

National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2011–0817; FRL–9758–6]

RIN 2060–AQ93

National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On July 18, 2012, the EPA proposed amendments to the National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and the Standards of Performance for Portland Cement Plants. This final action amends the national emission standards for hazardous air pollutants for the Portland cement industry. The EPA is also promulgating amendments with respect to issues on which it granted reconsideration on May 17, 2011. In addition, the EPA is amending the new source performance standard for particulate matter. These amendments promote flexibility, reduce costs, ease compliance and preserve health benefits. The amendments also address the remand of the national emission standards for hazardous air pollutants for the Portland cement industry by the United States Court of Appeals for the District of Columbia Circuit on December 9, 2011. Finally, the EPA is setting the date for compliance with the existing source national emission standards for hazardous air pollutants to be September 9, 2015.

DATES: This final rule is effective on February 12, 2013. The EPA is setting the compliance date for existing open clinker storage piles to be February 12, 2014.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2011–0817. All documents in the docket are listed in the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, for example, confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, EPA West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Ms. Sharon Nizich, Office of Air Quality Planning and Standards; Sector Policies and Programs Division, Minerals and Manufacturing Group (D243–04); Environmental Protection Agency; Research Triangle Park, NC 27111; telephone number: (919) 541–2825; fax number: (919) 541–5450; email address: *nizich.sharon@epa.gov.* For information about the applicability of the NESHAP or NSPS contact Mr. Patrick Yellin, Monitoring, Assistance and Media Programs Division (2227A), Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, Washington, DC 20460; telephone number (202) 654–2970; email address *yellin.patrick@epa.gov.*

SUPPLEMENTARY INFORMATION:

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

APCD air pollution control devices
CAA Clean Air Act
CBI confidential business information
CDX Central Data Exchange
CEMS continuous emission monitoring systems
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CISWI commercial and industrial solid waste incinerators
CMS continuous monitoring system
COMS continuous opacity monitoring system
CO_2 carbon dioxide
CPMS continuous parametric monitoring system
D/F dioxins and furans
EPA Environmental Protection Agency
ESP Electrostatic Precipitators
ERT Electronic Reporting Tool
FR Federal Register
gr/dscf grains per dry standard cubic foot
HAP hazardous air pollutants
Hg mercury
HCl hydrogen chloride
ICR information collection request
Lb/ton pound per ton
MACT maximum achievable control technology
meHg methylmercury
NAICS North American Industry Classification System
NAS National Academy of Science
NESHAP National Emissions Standards for Hazardous Air Pollutants
NHSM Nonhazardous Secondary Materials
NO_X Nitrogen Oxides
NRC National Research Council
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
oHAP Non-dioxin organic hazardous air pollutants
OMB Office of Management and Budget
PCA Portland Cement Association
PM particulate matter
ppm(v) (d,w) parts per million (by volume) (dry, wet)
RATA Relative Accuracy Test Audit
RfD reference dose
RIA regulatory impact analysis
RTC Response to Comment
RTO regenerative thermal oxidizers
SIP state implementation plan
SO_2 Sulphur Dioxide
THC total hydrocarbons
tpy tons per year
TTN Technology Transfer Network
$\mu g/m^3$ micrograms per cubic meter
UPL Upper Prediction Limit
UMRA Unfunded Mandates Reform Act
TEOM Tapered Element Oscillating Microbalance
VCS voluntary consensus standards
WWW worldwide web

Background Information Document. On July 18, 2012 (77 FR 42368), the EPA proposed to amend the Portland cement manufacturing industry NESHAP and the Portland cement plant new source performance standards (NSPS). In this action, we are taking final action on this proposal. A summary of the public comments on the proposal and the EPA's responses to those comments is available in Docket ID Number EPA–HQ–OAR–2011–0817.

Organization of this Document. The information presented in this preamble is organized as follows:

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I. General Information

A. Executive Summary

In this action the EPA is finalizing amendments to the NESHAP for Portland cement plants and to the NSPS for Portland cement plants. These amendments respond to petitions for reconsideration filed by the Portland cement industry and to a decision by the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The EPA is retaining the stack emission standards for mercury, hydrogen chloride (HCl), and total hydrocarbons (THC) under the NESHAP, amending the stack emission standard for particulate matter (PM) under the NESHAP, and making a conforming amendment to the NSPS for PM. The amendments also include provisions which account for commingled HAP emissions from coal mills that are an integral part of the kiln, establish a continuous monitoring regime for parametric monitoring of PM, set work practice standards for startup and shutdown, and revise the compliance date for the PM, mercury, HCl, THC and clinker storage pile existing source standards under the NESHAP. The EPA is also retaining the affirmative defense for civil penalties for violations of emission limits occurring as a result of a malfunction.

These amendments are based on sound technical and legal justifications, and result in cost savings and compliance flexibility for the Portland cement industry. This result is consistent with Executive Order 13563.

1. Purpose of the Regulatory Action

a. Need for the Regulatory Action

The EPA is amending the NESHAP for the Portland cement source category and the NSPS for Portland cement plants issued under sections 112(d) and 111(b) of the Clean Air Act (CAA). The most significant amendment is to the NESHAP and NSPS for PM, to correct monitoring issues with the PM compliance regime as promulgated in the 2010 final rule. As a result of this amendment, the EPA is also setting a compliance date of September 9, 2015, for meeting the PM, mercury, HCl and THC existing source NESHAP.

This final action also addresses the remand by the DC Circuit in *Portland Cement Ass'n* v. *EPA,* 665 F. 3d 177 (DC Cir. 2011). In that case, the court upheld all of the EPA's methodology for establishing the Portland cement NESHAP, denied all petitions for review challenging the NSPS, but also held that the EPA had arbitrarily denied reconsideration of the NESHAP to take into account the effect of the EPA's Nonhazardous Secondary Materials (NHSM) rule on the standards. The NHSM rule, issued after the NESHAP was promulgated, had the effect of reclassifying some cement kilns as commercial and industrial solid waste incinerators (CISWI) and thus could have an effect on the standards. The court also stayed the open storage clinker pile standards.

We are also amending various implementation requirements to provide more compliance flexibility for affected sources. In addition, the amendments address the issues on which the EPA previously granted reconsideration. See 76 FR 28318 (May 17, 2011).

b. Legal Authority for the Regulatory Action

These amendments implement sections 112(d) and 111(b) of the CAA. Section 112 of the CAA establishes a regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. After the EPA identifies categories of sources emitting one or more of the HAP listed in section 112(b) of the CAA, section 112(d) requires the EPA to promulgate technology-based NESHAP for those sources. Section 112(i)(3)(A) requires that the compliance date for existing sources shall be ''as expeditiou[s] as practicable,'' but not more than 3 years after a standard's effective date. Section 111 of the CAA requires that NSPS reflect the application of the best system of emission reductions achievable which, taking into consideration the cost of achieving such emission reductions, and any non-air quality health and environmental impact and energy requirements, the Administrator determines has been adequately demonstrated.

2. Summary of Major Provisions

a. PM Emission Standards

As proposed, the EPA is amending the existing and new source PM standards in the NESHAP to require manual stack testing in lieu of PM continuous emission monitoring systems (CEMS) for compliance determinations and requiring that a site-specific parametric operating level be established using a PM continuous parametric monitoring system (CPMS). We are changing the numeric emissions value of those standards for existing sources to 0.07 pounds per ton (lb/ton) clinker based on manual stack testing and 0.02 lb/ton clinker for new and reconstructed sources based on manual stack testing. The PM standards under the NSPS for modified sources are likewise amended to 0.07 lb/ton clinker based on manual stack testing and 0.02 lb/ton clinker for new and reconstructed sources based on manual stack testing.

b. Response to Remand

Consistent with the court's remand, the EPA has removed all of the CISWI kilns from the database used to set the 2010 existing source standards for PM,

mercury, HCl and THC. This analysis informed the level of the final standards discussed immediately below.

c. Other Emissions Standards

As proposed, the EPA is changing the alternative organic HAP (oHAP) standard from 9 parts per million (ppm) to 12 ppm. The EPA is not changing the existing or new source standards for mercury, THC or HCl.

d. Standards During Startup and Shutdown

The EPA is amending the emission standards applicable during periods of startup and shutdown from numerical standards to work practice standards.

e. Compliance Dates for NESHAP

As proposed, the EPA is establishing a compliance date of September 9, 2015, for existing source standards for PM, mercury, HCl and THC. The EPA is establishing February 12, 2014, as the compliance date for the standards for existing open clinker storage piles. New source standards continue to apply to all sources which commenced construction or reconstruction after May 6, 2009.

f. Final Action on Reconsideration

The EPA is also taking final action on the remaining issues on which it granted reconsideration on May 17, 2011.

3. Cost Impacts of These Amendments

We estimate that revising the means of demonstrating compliance for the PM, alternative organic HAP standards and requiring work practices for open clinker storage piles will save industry $52 million annually.

4. Summary of Final Standards

Table 1 shows the final standards for the Portland Cement Manufacturing Industry NESHAP and the Portland Cement Plants NSPS.

TABLE 1—EXISTING AND NEW SOURCE STANDARDS

Pollutant	Existing source standard	New source standard
Mercury	55 lb/MM tons clinker	21 lb/MM tons clinker.
THC	24 ppmvd	24 ppmvd.
PM	0.07 lb/ton [a] clinker (3-run test average)	0.02 lb/ton [b] clinker (3-run test average).
HCl	3 ppmvd	3 ppmvd.
Organic HAP (alternative to Total Hydrocarbons).	12 ppmvd	12 ppmvd.

[a] Also applies to NSPS modified sources.
[b] Also applies to NSPS new and reconstructed sources.

B. Does this action apply to me?

Categories and entities potentially regulated by this final rule include:

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS NESHAP AND NSPS FINAL ACTION

Category	NAICS code [a]	Examples of regulated entities
Industry	327310	Portland cement manufacturing plants.
Federal government		Not affected.
State/local/tribal government		Portland cement manufacturing plants.

[a] North American Industry Classification System.

Table 2 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility will be regulated by this action, you should examine the applicability criteria in 40 CFR 60.60 (subpart F) or in 40 CFR 63.1340 (subpart LLL). If you have any questions regarding the applicability of this final action to a particular entity, contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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

In addition to being available in the docket, an electronic copy of this final action will also be available on the World Wide Web (WWW) through the EPA's Technology Transfer Network (TTN). Following signature by the EPA Administrator, a copy of this final action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control. In addition, more information can be obtained at the following address: *http://www.epa.gov/airquality/cement.*

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final action is available only by filing a petition for review in the court by April 13, 2013. Under section 307(b)(2) of the CAA, the requirements established by the final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000,

Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background Information

A. What is the statutory authority for these amendments?

Section 112 of the CAA establishes a regulatory process to address emissions of HAP from stationary sources. After the EPA has identified categories of sources emitting one or more of the HAP listed in section 112(b) of the CAA, section 112(d) requires us to promulgate NESHAP for those sources. For ''major sources'' that emit or have the potential to emit 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of a combination of HAP, these technology-based standards must reflect the maximum reductions of HAP achievable (after considering cost, energy requirements and non-air quality health and environmental impacts) and are commonly referred to as maximum achievable control technology (MACT) standards.

The statute specifies certain minimum stringency requirements for MACT standards, which are referred to as ''floor'' requirements. See CAA section 112(d)(3). Specifically, for new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best controlled similar source. The MACT standards for existing sources can be less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources (for which the Administrator has emissions information) in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources).

In developing MACT, we must also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of the cost of achieving the emissions reductions, any non-air quality health and environmental impacts, and energy requirements. See CAA section 112(d)(2).

Under section 112(i)(3)(A), compliance dates for existing sources shall ''be as expeditiou[s] as practicable'', but in no event later than 3 years after the date of publication of the final rule in the **Federal Register**. The EPA may set a revised compliance date of a MACT standard when amending that standard, see *NRDC* v. *EPA*, 489 F. 3d 1364, 1373–74 (D.C. Cir. 2007), but any such amended compliance date must still establish ''compliance as expeditiously as practicable.''

Section 111(b) requires the EPA to set standards for emissions that ''reflect the degree of emission limitation achievable through the application of the best system of emission reduction.'' See CAA section 111(a)(1). In contrast to the NESHAP floor setting process, NSPS requires the EPA to take into account the ''cost of achieving'' emissions reductions, as well as health, environmental, and energy considerations. *Id.*

B. What actions preceded this final rule?

The history of this final rule, commencing with the 1999 standards and proceeding through the amendments issued in September 2009, is set out in detail in 75 FR 54970 (Sept 9, 2010). The Portland Cement Association (PCA) and several cement companies filed petitions for reconsideration of aspects of those amendments (copies of the petitions are in the Portland Cement Reconsideration docket, EPA–HQ–OAR–2011–0817). On May 17, 2011, the EPA granted reconsideration of various issues, and denied the petitions to reconsider as to the remaining issues. See 76 FR 28318 (May 17, 2011). On December 9, 2011, the D.C. Circuit issued an opinion upholding the NESHAP itself (as well as the section 111 NSPS), but finding that the EPA had arbitrarily failed to grant reconsideration to consider the effect of the EPA's NHSM rule on the standards (76 FR 15456 (March 21, 2011)), The NHSM rule had the effect of reclassifying some cement kilns as commercial and solid waste incinerators. See *Portland Cement Ass'n* v. *EPA*, 665 F. 3d 177, 186–189 (D.C. Cir. 2011). The court did not stay any of the numerical emission standards, but did stay the work practice standards for open clinker storage piles pending the conclusion of the reconsideration process. See 665 F. 3d at 194.

In this action, the EPA is responding to the court's remand. For existing sources, the EPA had done so by removing all kilns classified as CISWI units from the data used to establish the 2010 NESHAP standards. The EPA then recalculated each of the floors based on this dataset (the 2010 dataset minus CISWI units) and made beyond-the-floor determinations based on the recalculated floors. The EPA believes that this approach is properly responsive to the court's remand. See 665 F. 3d at 188 where the court referred favorably to this type of recalculation. For new sources, EPA used the same data as used to establish the 2010 floors—namely the performance of the best controlled similar sources as required by section 112(d)(3).

III. Summary of Final Amendments to Subpart LLL and Subpart F

As discussed in the preamble of the proposed rule, 77 FR 42368, in this final action the EPA is finalizing several amendments to Subpart LLL and Subpart F. These amendments are summarized below.

A. Reconsideration of Standards

As noted above, EPA has responded to the action of the DC Circuit by removing all CISWI cement kilns from the database used to establish the existing source standards, and recalculating existing source floors and standards from that revised database. As described in the preamble of the proposal, the EPA had determined based on the final NHSM rule that there are 24 cement kilns which combust solid waste. 77 FR 42372. During the comment period, one company provided reliable information in its comments regarding the materials it processes indicating that one of these kilns is, in fact, a cement kiln (meaning that the EPA had properly classified it as a cement kiln in the 2010 rulemaking).[1] After reviewing the information provided, the EPA agrees that this source should not be classified as a CISWI kiln and, therefore, should not be removed from the Portland cement kiln database. We received no other comments concerning the identification of cement kilns and CISWI units. There are thus now 23 kilns identified as combusting solid waste and therefore classified as CISWI units. As directed by the Court's decision, we removed these 23 kilns from the database and recalculated the floors. This calculation resulted in the same floors as proposed in the July 2012 proposal.

Consistent with this analysis, the EPA is finalizing amendments to the emission standards as follows:

[1] The company burns dried biosolids as a fuel which are not classified as solid wastes. Refer to the Docket, No. EPA–HQ–OAR–2011–0817–0482.

1. PM Emission Standards

The EPA is revising several provisions of the emission standards for PM as follows:

- Changing the compliance basis for the PM standards from continuous monitoring with a PM CEMS to a manual three run stack test, amending the level and averaging time of the standard, and requiring a continuous parametric monitoring system using a CPMS. As a consequence, the EPA is also:
- Amending PM standards under the NESHAP for existing sources to 0.07 lb/ton clinker based on manual stack testing, and 0.02 lb/ton clinker for new and reconstructed sources based on manual stack testing;
- Amending PM standards under the NSPS for modified sources to 0.07 lb/ton clinker based on manual stack testing and 0.02 lb/ton clinker for new and reconstructed sources likewise based on manual stack testing;
- Requiring that sources establish a site-specific parametric operating limit for PM, and requiring that the parametric limit be continuously monitored using a PM CPMS;
- Requiring that sources retest once a year to reset the PM CPMS operating limit;
- Adding a provision that, if a source exceeds that site-specific parametric operating limit, it must conduct corrective action including performing a Method 5 or 5I performance test within 45 days; in addition, if the source exceeds that parametric limit four times in a calendar year, the source is presumed to be in violation of the PM emissions standard itself, subject to rebuttal by the source.

2. Mercury Standard

As proposed, the EPA is establishing a standard for mercury of 55 pounds per million (lb/MM) tons clinker for existing sources and is not changing the emission standard (21 lb/MM tons clinker) for new sources. The emission standard for existing sources is the same as the 2010 standard but is a beyond the floor standard.

3. Other Emissions Standards

As the Court requested, the EPA removed the CISWI units from the database and re-calculated the standards for THC and HCl. The standards remain the same as they were in the final 2010 rule. See also 76 FR 21149, 21152, and 21154 explaining why beyond the floor standards for THC and HCl are not justified. The 2010 rules provide an alternative to the THC standard whereby sources can meet a limit for non-dioxin organic HAP by measuring those HAP directly rather than meeting the standard for THC (a surrogate for non-dioxin organic HAP). As proposed, the EPA is changing the level of the alternative non-dioxin organic HAP standard from 9 ppm to 12 ppm. Table 3 summarizes the Final Existing and New Source Standards

TABLE 3—EXISTING AND NEW SOURCE STANDARDS [a]

Pollutant	Existing source standard	New source standard
Mercury	55 lb/MM tons clinker	21 lb/MM tons clinker.
THC	24 ppmvd	24 ppmvd.
PM	0.07 lb/ton clinker (3-run test average)	0.02 lb/ton clinker (3-run test average).
HCl	3 ppmvd	3 ppmvd.
Organic HAP [b]	12 ppmvd	12 ppmvd.

[a] Standards for mercury and THC are based on a 30-day rolling average. The standard for PM is based on a three-run test. If using a CEMS to determine compliance with the HCl standard, the floor is also a 30-day rolling average.
[b] If the source opts to comply with the THC emission limit, this standard does not apply.

B. Continuously Monitored Parameters for Alternative Organic HAP Standard (With THC Monitoring Parameter)

In addition to amending the level of the alternative oHAP standard (i.e., the standard whereby sources meet a standard for oHAP rather than for THC), the EPA is amending the provisions for the site-specific THC operating parameter for that alternative standard (where THC is a site-specific parameter monitored continuously to show compliance with the oHAP standard). The THC operating parameter is established based on THC levels measured during the successful stack test where oHAP are measured directly to demonstrate compliance. As amended, if compliance source testing of oHAP averages a value that is 75 percent or less of the emission limit for oHAP, the facility is allowed to establish a THC parametric operating level corresponding to 75 percent of the oHAP emission limit. We are adopting this provision to avoid penalizing lower-emitting sources by burdening them with the most stringent parametric operating levels. The EPA is adopting a similar provision for continuous PM parametric monitoring, for the same reason (see Section IV.A below). Sources which show oHAP emissions in compliance, but greater than 75 percent of the standard, must establish the average THC concentration measured during the 3-hour organic HAP test and use that as the site-specific THC operating level. Thus, the parametric monitoring level for THC will be the level corresponding to oHAP levels of 75 percent of the standard or the THC level of the oHAP performance test, whichever is higher.[2] Compliance with the oHAP standard will be shown as a ratio of three test runs during mill-on conditions and three test runs during mill-off conditions, with the percentage of operating time spent in each condition determining the ratio. The parametric operating level will be set according to average THC values measured during these same test runs, or to the default value of 75 percent of the standard, as just explained. In addition, the EPA will allow facilities to extend the testing time of the oHAP performance test if they believe extended testing is required to adequately capture THC variability over time. This final rule further requires that the stack test for oHAP be repeated every 30 months to establish a new site-specific THC parameter.

C. Allowing Sources With Dry Caustic Scrubbers To Comply With HCl Standard Using Performance Tests

The 2010 rule allows sources equipped with wet scrubbers to comply with the HCl standard by means of periodic performance tests rather than with continuous monitoring of HCl with a CEMS. Sources electing to comply by means of stack tests must establish continuously monitored parameters including liquid flow rate, pressure, and pH. Under this final rule, kilns with dry scrubbers may also demonstrate

[2] If a source believes that monitoring non-methane THC rather than total THC is a more reliable indicator of its oHAP emissions, it can submit an alternative monitoring request pursuant to the requirements of 40 CFR 63.8(f).

compliance with the HCl emissions limit by means of an initial and periodic stack test rather than with continuous compliance monitoring with an HCl CEMS. If a kiln equipped with a dry scrubber chooses this alternative, this final rule requires that the sorbent injection rate used during a successful performance test be recorded and then continuously monitored to show that the injection rate remains at or above the rate used during the performance test.

Where either wet or dry scrubbers are used, owners and operators may also establish sulfur dioxide (SO_2) as an operating parameter, rather than, for example, sorbent injection rate, liquid injection rate or pressure drop. If the owner or operator of a scrubber-equipped kiln makes this choice, it must establish the SO_2 operating limit equal to the average of the HCl levels recorded during the HCl performance test, and meet that operating limit on a 30 day rolling average basis. If a source exceeds any established parameter level, it must retest for HCl in order to verify compliance with the HCl emissions standard and must verify or re-establish the parametric monitoring levels as well.

At a minimum, a repeat performance test to confirm compliance with the HCl emissions limit is required every 30 months.

D. Alternative PM Limit

The 2010 final rule established an alternative PM limit to accommodate situations where kilns combine exhaust gas from various operations. 77 FR 42382. The equation establishing the alternative limit contained certain technical errors which the EPA proposed to correct. As proposed, this final rule revises the alternative PM equation so that it includes exhaust gas flows from all sources that would potentially be combined, including exhausts from the kiln, the alkali bypass, the coal mill, and the clinker cooler, for an existing kiln. The EPA is thus finalizing the following equation:

$$PM_{alt} = 0.0060 \times 1.65 \times (Q_k + Q_c + Q_{ab} + Q_{cm})/(7000)$$

Where:

PM_{alt} = The alternative PM emission limit for commingled sources.

0.0060 = The PM exhaust concentration (grains per dry standard cubic feet (gr/dscf)) equivalent to 0.07 lb per ton clinker where clinker cooler and kiln exhaust gas are not combined.

1.65 = The conversion factor of lb feed per lb clinker.

Q_k = The exhaust flow of the kiln (dscf/ton feed).

Q_c = The exhaust flow of the clinker cooler (dscf/ton feed).

Q_{ab} = The exhaust flow of the alkali bypass (dscf/ton feed).

Q_{cm} = The exhaust flow of the coal mill (dscf/ton feed).

7000 = The conversion factor for grains (gr) per lb.

If exhaust gases for any of the sources contained in the equation are not commingled and are exhausted through a separate stack, their value in the equation would be zero. The alternative PM equation for new sources is identical to the existing source equation except the PM exhaust concentration used in the equation is 0.002 gr/dscf, which is equivalent to the new source PM limit of 0.02 lb/ton clinker.

E. Coal Mills

The EPA discussed at length in the preamble to the proposed rule a potential regulatory regime to cover situations where a portion of the kiln exhaust is ducted to the coal mill. See 77 FR 42383–85; see also the regulatory text at 77 FR 42398, 42402–06, 42408–09. To assure that cement kilns do not exhaust untreated HAP through coal mills, and to assure accurate accounting of commingled emissions so that cement kilns are not penalized for commingling emissions where it makes sense to do so, the EPA is finalizing rules applicable to kiln/coal mill emissions for two configurations. In one, a portion of the kiln exhaust is ducted to a coal mill, and then the coal mill exhaust is commingled with remaining kiln exhaust and discharged through the main kiln stack. In the other, a portion of the kiln exhaust is routed through the coal mill and discharged through the coal mill stack.

In the case of a coal mill that receives and discharges a portion of the cement kiln exhaust, this final rule requires that the sum of the mercury, THC and HCl in the kiln exhaust diverted to the coal mill, and the kiln exhaust exhausted from the main kiln stack, must not exceed the subpart LLL emission limits for each respective HAP or HAP surrogate. The facility must document the contribution of the emissions diverted to the coal mill. For mercury, the rule allows tests to be performed downstream of the coal mill to take advantage of any mercury removal that occurs in the coal mill air pollution control device, and to avoid double counting emissions from mercury that becomes re-entrained in the coal. For THC and HCl, the rule allows tests to be performed upstream of the coal mill to avoid any THC or HCl that might be emitted by the coal. For owners and operators who believe that the impact of the testing location (upstream or downstream of the coal mill) would not result in their exceeding the kiln mercury, THC or HCl emissions limits and wish to conduct all their THC, HCl and mercury testing at a single location, this final rule allows testing either upstream or downstream of the coal mill. For sources complying with the alternate organic HAP limit, the facility would not be required to test for THC emissions, but would test for the organic HAP and add that concentration to the remaining emission points to estimate their total emissions for organic HAP.

A cement kiln that commingles emissions from its coal mill with all other kiln exhaust emissions and discharges through a single stack could simply meet the kiln emission limits. In the case of PM, the additional flow from the coal mill would be accounted for in the equation used to determine PM contributions from commingled flows. See section D above. In this configuration, the source would also have the option of monitoring and/or testing kiln exhaust gases prior to the introduction of the coal mill exhaust gas, and testing the kiln gas diverted to the coal mill. In this case this final rule requires that the sum of the mercury, THC (or organic HAP if the source chooses the alternative organic HAP limit), and HCl in the kiln exhaust diverted to the coal mill plus the kiln exhaust measured in the main kiln exhaust must not exceed the subpart LLL emission limits for each respective HAP or HAP surrogate.

The same provisions for coal mills also apply to kilns equipped with an alkali bypass. The one minor exception is that for PM, the summed PM emissions from the kiln and alkali bypass must be equal to or less than the PM limit in subpart LLL. Tests for PM from the alkali bypass must be conducted downstream of the alkali bypass air pollution control devices (APCD) to account for those emission reductions.

With regard to PM, the EPA stated at proposal that where a coal mill receives and discharges a portion of the cement kiln exhaust, the kiln owner operator would have to demonstrate compliance with the 40 CFR 60 subpart Y standard for PM. Although the subpart Y standard is numerically higher than the subpart LLL PM standard, EPA assumed that control would be to the same level because the subpart Y PM standard is predicated on use of fabric filer control technology. 77 FR 42383/2. However, a commenter pointed out accurately that this proposal contravened the basic principle EPA indicated it was adopting here of not allowing diverted kiln emissions to meet a more lenient standard than required by the NESHAP,

and further indicated that EPA had failed to show that these diverted PM emissions were controlled as required by section 112(d)(2) and (3) of the Act. EPA agrees with this comment, and accordingly is indicating in the final rule that commingled emissions in this situation would be required to meet the subpart LLL NESHAP for PM. Because coal mill stacks are controlled with fabric filters, we project that they can meet the subpart LLL numeric standard without further controls. See 77 FR 42383. Coal mill stacks will be required to meet annual PM performance testing and combine the measured emissions with PM emissions from the separated alkali stack, bypass stack, and/or main kiln as required in sections 60.62(b)(3), 63.1349 and 63.1350 of this rule.

This final rule also states that sources equipped with an alkali bypass stack or sources that exhaust kiln gases to a coal mill that exhausts through a separate stack are not required to install CEMS on these stacks. Instead of installing a CEMS, such sources may use the results of the initial and subsequent performance test to demonstrate compliance with the PM, THC, HCl and mercury emissions limits. Note that for the main kiln exhaust, the CEMS requirements remain.

We expand on these monitoring provisions below.

1. Mercury

Although mercury from the kiln stack is monitored using a CEMS, mercury emissions from the coal mill are based on a periodic performance test and use of the gas flow rate to the coal mill. Performance tests for mercury must be conducted annually unless and until the tested mercury levels are below the method detection limits for two consecutive years, after which tests may be conducted every 30 months. The performance test results must be summed with the emissions from the kiln stack to determine compliance. The coal mill exhaust mercury emissions are calculated on a mass basis using the measured mercury concentration and the coal mill exhaust gas flow. The coal mill exhaust flow is established using a continuous monitoring system (CMS), or the design maximum flow rate. Mass mercury emissions from the coal mill would be summed with the hourly mercury emissions from the kiln measured by the mercury CEMS. Hourly mercury emissions are then summed to calculate the rolling 30-day mass mercury emissions. This number is then divided by the corresponding 30 days of clinker production to determine the 30-day rolling average. This final rule provides equations for summing emissions from the coal mill with the mercury emissions from the kiln to determine continuous compliance. To see an example calculation, see Section 4 of the Portland Cement Reconsideration Technical Support Document (developed for the proposal), docket item EPA–HQ–OAR–2011–0817–0225.

2. THC and HCl

In this case, site specific kiln stack emission limits (to be continuously monitored) are to be calculated taking into consideration the volumetric exhaust gas flow rates and concentrations of all applicable effluent streams (kiln stack, coal mill and alkali bypass) for the kiln unit. In order to determine the flow rates and concentrations of THC and HCl in the coal mill and alkali bypass streams, the source must test every 30 months using the appropriate test method. For HCl, the performance test must be performed using Method 321 in Appendix A to 40 CFR Part 63. For measurement of THC, Method 25A in Appendix A–7 to 40 CFR Part 60 is required. With these data, the concentration of THC and HCl that must be monitored by the kiln CEMS in order to demonstrate compliance with the kiln MACT limit can be calculated using the equations in this final rule. As with mercury, the coal mill flow rate used to calculate the allowable main kiln stack THC and HCl concentrations can be based on a CMS, or on the maximum design flow rate. The sum of the kiln CEMS and the maximum emissions from the coal mill or alkali bypass must be at or below the subpart LLL limits for THC and HCl. See Section 4 of Portland Cement Reconsideration Technical Support Document (developed for the proposal), docket item EPA–HQ–OAR–2011–0817–0225, for an example calculation.

Also, as a result of these revisions, the EPA is revising the definition of kiln to include inline coal mills and adding a definition of inline coal mill.

F. NESHAP Compliance Date Extension for Existing Sources

This final rule establishes that the compliance date for the amended PM standard, and for the THC, mercury and HCl standards, for existing sources for kilns, clinker coolers and raw material dryers is September 9, 2015. This final rule also establishes February 12, 2014, as the compliance date for the existing open clinker storage pile work practice standards. A detailed discussion of these compliance dates can be found in Section V.D. below.

G. Section 112 Eligibility To Be a New Source

The EPA is not changing the date for new source eligibility under the NESHAP. Thus, a source that commenced construction or reconstruction after May 6, 2009, would remain subject to the section 112 new source standards. A more detailed discussion of this topic can be found below in Section V.E.

H. Other Testing and Monitoring Revisions

In this action we are finalizing the proposed corrections and clarifications to the 2010 rule including changes to: Equations for calculating rolling operating day emissions rates; procedures that include extraneous wording; and cross references and typographical errors in the rule.[3]

For sources that are required to monitor HCl emissions with a CEMS, we are revising the requirements for using HCl CEMS to define the span value for this source category, to include quality assurance measures for data collected under ''mill off'' conditions, and to clarify use of performance specification (PS) 15. This final rule also removes from the standard the oxygen correction factors for raw material dryers and makes minor, non-substantive changes to the sections and paragraphs below:

- Section 60.62(d).
- Section 60.63(b)(1)(i) and (ii), (b)(2), (f)(1), (2), (4), (5), (h)(1) and (6) through (9) (i).
- Section 60.64(b)(2).
- Section 60.66.
- Section 63.1340(b)(1) and (6) through (8).
- Section 63.1346(a) and (c) through (e).
- Section 63.1348(a)(2), (3)(i) through (iii), (a)(4)(i)(A), (a)(4)(ii) and (iv).
- Section 63.1348(b)(1)(i), (iii) and (iv).
- Section 63.1348(b)(3), (5), (6)(i), (8) and (c)(2)(iv).
- Section 63.1349(a), (b)(3), (d)(1) and (d)(2) and (e).
- Section 63.1350(d)(1)(i) and (ii), (f), (f)(2)(i) and (iii), (f)(3), (f)(4), (g)(1) and (2), (k), l(2), (m)(3), (m)(10) and (11), (o) and (p).
- Section 63.1352(b).
- Section 63.1356.
- In addition, we are adding requirements in section 63.1348(a), that

[3] We note that these changes required the agency to reprint sections of regulatory text. See e.g. 63.1348(a)(3)(i). In reprinting these passages, EPA has not reopened, reconsidered, or otherwise reevaluated the substance of these provisions but rather is only making the needed technical alteration.

a cement kiln that becomes subject to the rule after having been subject to the CISWI regulations, must meet all the initial compliance testing requirements even if they were previously subject to Subpart LLL.

I. Miscellaneous Amendments

We are also finalizing amendments to clarify various requirements in this final rule including issues of applicability, treatment of multiple sources that vent to a single stack, third party certification, definitions and use of bag leak detection systems when PM CPMS are in use.

For raw material, clinker or finished product storage bins, we have clarified that the requirements of this final rule apply only at facilities that are a major source (see section 63.1340(b)(6)) and that affected sources that are subject to subpart OOO (standards for nonmetallic mineral processing) are not subject to the requirements of subpart LLL (see section 63.1340(c)).

With regard to the NSPS, to clarify the recordkeeping and reporting requirement in section 60.65(a) to submit excess emission reports, we have added to section 60.61 of the NSPS a definition of ''excess emissions'' to mean ''with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.'' To clarify what data are used in the calculation of emissions, or used in the calculation of parametric levels that are used to demonstrate continuous compliance, we added to this section a definition of ''operating day'' to mean ''a 24-hour period beginning at 12:00 midnight during which the kiln operates at any time. For calculating rolling 30-day average emissions, an operating day does not include the hours of operation during startup or shutdown.'' The definition for ''operating day'' in section 63.1341 of the NESHAP is revised to be consistent with the above definition. We also became aware that some raw material dryers may be used to dry materials other than kiln feed and we have revised the definition of ''raw material dryer'' in recognition of that fact.

J. Standards During Periods of Startup and Shutdown

In the 2010 final NESHAP, the EPA established separate standards for periods of startup and shutdown which differ from the main standards that apply during steady state operations. In this action, based on comments received and the EPA's reconsideration of several technical issues related to startup and shutdown, the EPA is adopting work practices in place of these numerical standards. The rationale and provisions for the work practice standards are discussed in detail in section IV.C.

The EPA is also clarifying the operating conditions during which these standards apply, including a definition of ''startup'' and ''shutdown''. Under the amended definition, startup begins when the kiln's induced fan is turned on and fuel combustion is occurring in the main burner of the kiln. Startup ends when feed has been continuously fed to the kiln for at least 120 minutes or when the kiln feed rate exceeds 60 percent of the kiln design limitation rate. Shutdown begins when continuous feed to the kiln is halted and ends when continuous kiln rotation ceases.

The startup and shutdown-related changes include:

- Adding a definition of startup and shutdown in section 63.1341, as described;
- Adding section 63.1346(f) describing work practice standards to be met during periods of startup and shutdown;
- Revising section 63.1347 to require that startup and shutdown procedures be included in the facility's operation and maintenance plan;
- Adding section 63.1355(f) requiring records of each startup and shutdown including the date, time and duration and the quantity of feed and fuel added to the kiln during startup and shutdown;
- Adding section 63.1348(b)(9) requiring continuous compliance by operating all air pollution control devices during periods of startup and shutdown.

K. Reporting for Malfunctions and Affirmative Defense for Violation of Emission Standards During Malfunctions

The EPA added to the September 9, 2010, final NESHAP rule an affirmative defense to civil penalties for violations of emissions limits that are caused by malfunctions. Various environmental advocacy groups, as well as the PCA, indicated that there had been insufficient notice of this provision. The EPA agreed and granted reconsideration. See 76 FR 28325 (May 17, 2011). This action finalizes the EPA's decision to retain the affirmative defense on reconsideration.

The EPA is retaining in the final NESHAP rule an affirmative defense to civil penalties for violations of emission standards that are caused by malfunctions. See 40 CFR 63.1341 (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We are also revising some of the regulatory provisions that specify the elements that are necessary to establish this affirmative defense as proposed with minor changes from proposal described later in this section. The source must prove by a preponderance of the evidence that it has met all of the elements set forth in section 63.1344. (See 40 CFR 22.24). The criteria are designed in part to ensure that the affirmative defense is available only where the event that causes a violation of the emission standard meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that the violation ''[w]as caused by a sudden, infrequent, and unavoidable failure of air pollution control, process equipment, or a process to operate in a normal or usual manner * * *.'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 63.1344 and to prevent future malfunctions.

Similar to actions taken in several other recent NESHAP amendments (see National Emissions Standards for Hazardous Air Pollutants From Secondary Lead Smelting, 77 FR 556, January 5, 2012, National Emission Standards for Hazardous Air Pollutant Emissions for Shipbuilding and Ship Repair (Surface Coating), and National Emission Standards for Wood Furniture Manufacturing Operations, 76 FR 72050, November 21, 2011), the EPA included an affirmative defense in the 2010 final rule and is retaining it in this rule (see section 63.1344). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission standards are ''continuous'' as required by 42 U.S.C. § 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole. In addition to the authority cited in support of the affirmative defense in the preamble to the proposed rule, the EPA notes that a recent court decision further supports

the EPA's authority to promulgate an affirmative defense. The United States Court of Appeals for the Fifth Circuit recently upheld the EPA's view that an affirmative defense provision is consistent with section 113(e) of the Clean Air Act. *Luminant Generation Co. LLC v. United States EPA,* 2012 U.S. App. LEXIS 21223 (5th Cir. Oct. 12, 2012) (upholding the EPA's approval of affirmative defense provisions in a CAA State Implementation Plan). As discussed in the preamble to the proposed rule (77 FR 42379), the EPA's view is that an affirmative defense to civil penalties for exceedances of applicable emission standards during periods of malfunction appropriately resolves an underlying tension inherent in many types of air regulation, to ensure continuous compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. See generally, *Virginia v. Browner,* 80 F.3d 869, 878 (4th Cir. 1996) (the EPA's interpretation that resolved a tension within the CAA is reasonable). The EPA has used its section 301(a)(1) authority to issue regulations necessary to carry out the Act in a manner that appropriately balances these competing concerns.

We are promulgating revisions to the affirmative defense provisions in section 40 CFR 63.1344 as described at proposal (77 FR 42380) and making some minor additional revisions. The phrase "emission limit" was changed to "emission standards" to reflect that the affirmative defense could be applicable to certain work practice standards. The phrase, "Off-shift and overtime labor were used, to the extent practicable to make these repairs" was removed. The term "notification" to "reporting" was changed to reflect that the root cause analysis required under affirmative defense would be submitted with other periodic reporting. The term "and monitoring" was deleted because monitoring malfunctions are defined differently than malfunctions of process and control units and the affirmative defense is intended to apply to malfunctions to affected units that cause a failure to meet an emission standard. The word "however" was removed to incorporate more plain language into the regulation. The phrase "the respondent fails" was removed and replaced with "you fail" to incorporate more plain language into the regulation. The word "its" was replaced with "your" to incorporate more plain language into the regulation. The phrase "all of the" was replaced with "your" also to incorporate more plain language into the regulation. The phrase "air pollution control practice" was shortened to "good practices" to incorporate more plain language into the regulation. In addition, the written report required when asserting an affirmative defense was changed from a separate "semiannual" report to a report that is submitted with the first periodic compliance, deviation report or excess emission report due after the event.

We are finalizing the reporting and recordkeeping associated with violations due to malfunctions as described at proposal (77 FR 42388) and making some minor additional revisions as described below.

- Revising section 63.1354(b)(vii) for reporting and recordkeeping violations due to malfunctions. The phrase "failure to meet a standard" was used to replace "deviation" in the requirement to report violations of the standard. This was changed because the EPA is not finalizing a definition of deviation in this subpart and the term is not defined in the general provisions.
- Revising section 63.1354(c) for reporting a failure to meet a standard due to a malfunction. In addition, the phrase "failure to meet a standard" was used to replace "deviation" in the requirement to report violations of the standard. This was changed because the EPA is not finalizing a definition of deviation in this subpart and the term is not defined in the general provisions.
- Revising section 63.1355(f) addressing recordkeeping during startup and shutdown. The proposed recordkeeping requirement applicable to startup and shutdown assumed that a numerical emission standard was applicable during startup and shutdown. In finalizing the work practice standards in 63.1346(f) there will no longer be a numerical emission standard applicable during startup and shutdown. As such the recordkeeping requirement must change to reflect the content of the work practice standard. Records must be kept of the date, time and duration of the periods when the work practice is applicable, as well as the fuel and feed data to demonstrate compliance with the work practice standard.

L. What are the compliance dates of the standards?

During the comment period, comments were received that confirmed the need for additional compliance time, since the revised standards can result in different compliance strategies relative to the 2010 final rule. Thus, as proposed, this final rule establishes the compliance date for the amended existing source standards including standards for PM, mercury, HCl and THC to be September 9, 2015. The existing source compliance date for the requirements for open clinker storage piles is February 12, 2014. New sources which commenced construction or reconstruction after May 6, 2009, would remain subject to the new source standards and a compliance date of February 12, 2013, or startup, whichever is later.

M. Open Clinker Storage Piles

The EPA has added work practice requirements for open clinker storage piles that will reduce fugitive dust emissions from these sources. This final rule also contains a definition of open clinker storage piles and requires that a source's operation and maintenance plan include the steps the facility will take to minimize fugitive dust emissions from open clinker storage piles. A detailed discussion of these requirements can be found in section V.C below.

IV. Summary of Major Changes Since Proposal

A. PM Parametric Monitoring

Changes to PM Parametric Monitoring. The EPA proposed the use of PM CPMS for continuous monitoring of PM emissions as a 30-day rolling average established by identifying the average PM CPMS response corresponding to the highest 1-hour PM compliance test. Failure to meet this 30-day rolling average would result in retesting, and more than four exceedances from the parametric limit in a year would be presumed (subject to possibility of rebuttal by the source) to be a violation of the emission standard itself. See 77 FR 42377. Industry commented that this requirement would trigger unnecessary retests for many facilities, especially for the lower-emitting sources. The issue of increased compliance burden falling on the lower emitting sources is legitimate. Sources with especially low PM limits in their performance test would be most at risk of exceeding a parametric limit due to a few emission spikes, even though they would still be operating well under the actual PM compliance limit. We also received comment that the highest PM performance test run may represent, in some circumstances, a number higher than the PM emissions standard. To avoid this eventuality we have changed the final rule to require setting the PM operating limit equivalent to the average of the three PM performance tests, which constitutes the demonstration of compliance with the standard. To avoid

penalizing lower emitting facilities, the EPA has modified the way PM CPMS operating limits are established. Sources whose compliance with the PM emission standard are shown to be 75 percent or below the emission limit in the PM method 5 compliance test will set their PM parametric operating limit to be a 30-day rolling average equivalent to that 75 percent level. In a recent rule (76 FR 15736, March 21, 2011), the EPA established 75 percent of the limit as a number that allows for compliance flexibility and is simultaneously protective of the emission standard, and the same technical basis is applicable here as well. Sources whose compliance with the PM emission standard are above 75 percent of the emission limit will establish their operating limit as a 30-day rolling average equal to the average PM CPMS values recorded during the PM compliance test. It should be noted that this provision affects the allowable level of the parametric limit, but does not change the PM emission limit that must be met.

B. Scaling for Continuous Parametric Monitoring of THC for Alternative OHAP Standard

As explained in section III.B above, the EPA is adopting a scaling approach for parametric monitoring of THC under the alternative organic HAP standard which is conceptually similar to the one just discussed for parametric monitoring of PM. This provision affects the allowable level of the THC parametric limit, but does not change the oHAP emission limit that must be met.

The EPA proposed the use of THC monitoring in conjunction with organic HAP compliance testing to determine a parametric operating limit option for monitoring continuous compliance with the alternative organic HAP standard. In the proposed rule the organic HAP parametric operating limit was established by correlating the highest of three organic HAP test results with the corresponding average THC concentration recorded by a parametric THC monitor. Industry commented that this requirement would trigger unnecessary retests for many facilities, especially for the best performing sources. Not wishing to penalize those sources showing good performance, and simultaneously wanting to be protective of the emission standard, the EPA is changing the way parametric THC operating levels are established. Sources whose compliance with the organic HAP emission standard are shown to be below 75 percent of the emission limit will set their operating limit to be a 30-day rolling average equivalent to that 75 percent level. Sources whose compliance with the organic HAP emission standard are at or above 75 percent of the emission limit will establish their operating limit as a 30-day rolling average equal to the average parametric THC values recorded during the organic HAP compliance test. Sources with an in-line kiln/raw mill will use the fraction of time the raw mill is on and the fraction of time that the raw mill is off, and calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off testing.

C. Work Practice Standard in Lieu of Numerical Emissions Limits for Periods of Startup and Shutdown

Under section 112(h) of the Act, the EPA may adopt a work practice standard in lieu of a numerical emission standard only if it is ''not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant''. This phrase is defined in the Act to apply to any situation ''in which the Administrator determines that * * * the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.'' CAA section 112(h)(1) and (2). In adopting numerical limits for startup and shutdown in the 2010 final NESHAP, the EPA rejected comments that it should adopt work practices as a standard during startup and shutdown. This was largely because the commenters had not addressed the issue of whether the requirements of section 112(h) had been met. See docket item EPA–HQ–OAR–2002–0051–3464, pp. 183–84. The EPA later denied petitions to reconsider this issue on the grounds that the agency had already provided ample opportunity for comment on the issue, which petitioners had used. See 76 FR at 28323. The DC Circuit dismissed all challenges to the startup and shutdown provisions in the NESHAP (665 F 3d at 189). The EPA granted reconsideration on several technical issues related to startup and shutdown—specifically, monitoring of mercury and PM during startup and shutdown and having an HCl limit of zero for kilns not equipped with CEMS (see 76 FR at 28325), but these issues are no longer relevant based on the approach adopted in this final rule.

In the proposed reconsideration rule, the EPA proposed to retain the numerical standards, but to use recordkeeping rather than measurements to document compliance with the numerical standard. 77 FR 42382–83. EPA further solicited comment ''on whether the numeric standards during startup and shutdown should be amended to provide work practices'', and suggested what potential work practices might be. *Id.* at 42383. Some commenters supported retention of numerical standards, stating that nothing in the record supports a decision by the EPA that numeric standards are not feasible to measure. However, these commenters provided no supporting technical data. We also received comments opposing numeric limits and supporting work practices in their stead. Commenters stated that any numeric limit should be based on actual data gathered during startup and shutdown, which the proposed limits are not, and that measurement of emissions during startup and shutdown poses significant technical problems, mainly based on CEMS calibration issues, and the duration of startups and shutdowns.

Industry has presented information specific to the cement industry to the EPA on technical issues associated with cement kilns measuring PM, mercury, THC and HCl during periods of startup and shutdown. See docket item EPA–HQ–OAR–2011–0817–0237[1] and PCA Meeting 9–15–11 monitoring presentation in the docket for this rulemaking, as well as their public comments. EPA has continued to evaluate these data. In light of all of these public comments and further evaluation of the data, the EPA has decided to establish work practice standards in lieu of numeric standards during startup and shutdown periods. The EPA is doing so because the application of measurement methodology is not practicable for technological and economic reasons. See CAA section 112(h)(2)(B).

The operation of kilns at cement manufacturing plants is different from many other sources. Kiln startups can last days, during which time fuels are switched and temperatures and moisture conditions fluctuate substantially. Also, cement kilns have two types of inputs—raw feed that is changed into clinker in the kiln, and kiln fuel. The cement kiln is sized to accommodate not just exhaust gas flow from combustion, but the gases evolved from the calcination of limestone and moisture that evaporates from the kiln feed. As a result of these factors, the difference in gas flow characteristics of a cement kiln during steady state operation and startup/shutdown is more pronounced than that for other combustion source categories. In addition, cement kilns begin introducing feed as part of the startup process which further exacerbates the transient and fluctuating nature of these

operations not only because of the impact of this feed on the exhaust gases, but because raw materials and fuels are introduced at opposite ends of the kiln, which results in countercurrent flow of the solid material in the kiln and kiln exhaust gas, increasing the turbulence, transience and fluctuating conditions. The result is that conditions change constantly when cement kilns are in startup or shutdown mode. These conditions make stack measurements, both manual and continuous, for this source category unreliable because the constant shifting in conditions prevents any stack measurement from being representative of anything but conditions at that precise moment. For that reason manual stack tests, which take place over a period of a few hours, would not be presenting accurate information, since they would not be reliably measuring conditions across the duration of the test.

There is no way to craft a testing regime to compensate for these testing issues at each kiln in a manner that can produce reliable and replicable results. Such modifications would be specific to that individual startup event—i.e. *ad hoc* and therefore not of general applicability or utility in showing compliance. Continuous measurements conducted during these periods for cement kilns are also subject to inaccuracies resulting from these rapidly changing conditions. The temperature changes of greater than one thousand degrees Fahrenheit, flue gas moisture changes greater than 20 percent, and gas flow changes over several thousand cubic feet per minute, as well as other factors such as flue gas molecular weight swings, combine to create a complex matrix of measurement variables not accounted for in a cement kiln CEMS installation. That is, CEMS for PM, HCl, Hg, and THC are not able to reliably accommodate all of these transient shifting variables when measuring cement kiln startup and shutdown emissions. As noted above, these issues are further exacerbated by the fact that cement kilns have multiple inputs (fuel and feed), and the clinker production process generates higher gas flows than would be expected based on just the fuel inputs. This fact also means that flue gas flow rates cannot be accurately calculated from fuel inputs alone.

The EPA regards situations where a measurement may yield a value which is analytically suspect, which is the case for cement kilns during startup and shutdown for the reasons just described, as being a situation where measurement is not ''technologically practicable'' within the meaning of section 112(h)(2)(B) of the Act. Unreliable measurements raise issues of practicability and of feasibility and enforceability (see section 112(h)(1)).[4]

The EPA is not finalizing its proposed approach of setting numerical emission limits for startup and shutdown and requiring that sources certify compliance with those limits by keeping certain records certifying that they used certain fuels and did not introduce feed into the kiln. Under the proposal, sources would have had to certify compliance with the standards for the various organics based on assumed combustion conditions. As pointed out persuasively in the public comments, combustion conditions during startup and shutdown are too widely varying to either reliably measure or calculate emissions because combustion conditions change widely during startup and shutdown, sources indicated that they could not certify compliance based on an assumed combustion condition. See docket item EPA–HQ–OAR–2011–0817–0506, p. 11 (''Until ideal combustion conditions can be met in the combustion chamber (adequate temperature and turbulence), the combustion process will be incomplete. While this should not impact fuel-derived hazardous air pollutants (chlorine and mercury), it will impact the emissions of organics and possibly PM''). In light of the measurement issues noted above and the fact that sources could not certify compliance under the proposed approach, the EPA is not finalizing the proposed approach of setting numerical limits for startup and shutdown and allowing sources to certify compliance with the limits by maintaining certain records.

Instead, for the reasons explained above, the EPA is establishing work practice standards to demonstrate compliance with startup and shutdown. The work practices that apply during startup and shutdown are as follows:

- During startup the kiln must initially use any one or combination of the following clean fuels: Natural gas, synthetic natural gas, propane, distillate oil, synthesis gas, and ultra-low sulfur diesel until the kiln reaches a temperature of 1200 degrees Fahrenheit.
- Combustion of the primary kiln fuel may commence once the kiln temperature reaches 1200 degrees Fahrenheit.
- All air pollution control devices must be turned on and operating prior to combusting any fuel.
- You must keep records as specified in § 63.1355 during periods of startup and shutdown.

For the purpose of identifying when the kiln is in a startup/shutdown mode and subject to work practices and when the kiln is subject to numerical emission limits, we are defining the beginning and ending of startup and shutdown. At proposal we defined startup as when the kiln's induced fan is turned on and shutdown was defined as beginning when feed to the kiln is halted. Commenters noted that a kiln may have the induced draft (ID) fan operating even when the kiln is completely shutdown, no fuel is being burned, and there is no potential for emissions. Therefore, we changed the startup definition to be when a shutdown kiln turns on the ID fan and begins firing fuel in the main burner, because this is the point where the potential for emissions to occur begins. Startup ends when feed is being continuously introduced into the kiln for at least 120 minutes or until the feed rate exceeds 60 percent of the kiln design limitation rate. We added the duration/load element to the definition of startup because during startup a kiln must begin adding feed material to achieve steady state operation. After feed is first introduced it requires up to two hours or sufficient feed to achieve 60 percent of maximum operation to achieve a representative steady-state condition. (See meeting notes, PCA November 28, 2012, in the docket for this rulemaking). Shutdown begins when continuous feed to the kiln is halted and ends when the kiln rotation ceases.

We believe these work practices, which include the requirement that all air pollution control devices be operating, will ensure that emissions during startup and shutdown will be lower than the standards that apply during steady state operations, given use of cleaner fuels, minimal raw material inputs, and operation of all control devices during these periods. See 77 FR 42382 (noting that emissions during startup and shutdown would be expected to be lower than during steady state operations for these reasons).

[4] The application of measurement methodology during cement kiln startup and shutdown would also not be ''practicable due to * * * economic limitation'' within the meaning of section 112(h)(2)(B) since it would just result in cost expended to produce analytically suspect measurements.

V. Summary of Significant Comments and Responses

A. Amendments to Existing Source and New Source Standards for PM Under CAA Sections 112(d) and 111(b)

1. Changes to Level and Averaging Time of Existing Source NESHAP

The EPA proposed to amend the existing and new source standards for PM. The floor for the existing source standards increased from 0.04 lb/ton clinker to 0.05 lb/ton clinker as a result of removing CISWI kilns from the database. See Section 8.3, Portland Cement Reconsideration Technical Support Document, June 15, 2012, Docket item EPA–HQ–OAR–2011–0817–0225; see also 77 FR 42372/3. Second, the EPA proposed to change the compliance regime for the standard from use of PM CEMS to stack testing, a consequence being that the standard would no longer be expressed as a 30-day average but rather as the average of three test runs. The EPA thus proposed to express the recalculated floor (i.e. 0.05 lb/ton clinker 30-day average resulting from the reanalysis) as .07 lb/ton of clinker (average of three test runs). The 0.07 lb/ton clinker standard expresses the recalculated floor (i.e. 0.05 lb/ton clinker) as a not-to-exceed value based on stack testing, using the Upper Prediction Limit equation to do so. See Portland Cement Reconsideration Technical Support Document, June 15, 2012, Docket item EPA–HQ–OAR–2011–0817–0225.[5]

The EPA further proposed to use CPMS for continuous parametric monitoring. This system responds to changes in PM concentration and generates a corresponding milliamp output signal. 77 FR 42376–77. The proposed PM parametric level was correlated to the highest recorded value during three test runs. A source would meet this site-specific level on a 30-day rolling average. Failure to meet this 30-day rolling average would result in retesting, and more than four deviations from the parametric level in a year would be presumed (subject to possibility of rebuttal by the source) to be a violation of the emission standard itself. See 77 FR 42377.

Our proposal to change the compliance regime from use of CEMS to stack tests reflected technical issues related to a PM CEMS' reliability with measuring the Portland cement PM standard. Specifically, the EPA discussed the reliability of measurements, obtained using PM CEMS calibrated as required by the mandated PS 11, below the level of the 2010 standard or the level of the recalculated PM floor. See 77 FR 42374–76. The EPA's judgment at proposal was that as a result of PM measurement uncertainties, "this correlation will not be technically or practically achievable for a significant number of cement kiln sources." *Id.* at 42376.

One commenter challenged the necessity of amending the standard to a stack test regime (apparently not realizing that the existing source standard also changed as a result of removing CISWI kilns from the database). First, the commenter maintained that the EPA has no authority to voluntarily change a promulgated MACT standard to make the standard less stringent, based on the language of section 112(d)(7). The commenter further maintained that the EPA had not definitively shown that PM CEMS calibrated pursuant to PS 11 could not be used to reliably measure the Portland cement PM standard. Specifically, the commenter stated that the various problems identified by the EPA at proposal are amenable to resolution by testing longer and more often, and argued that the EPA essentially admitted as much at proposal. The commenter noted that other technical problems, like the difficulty of accounting for varied particle sizes, could be resolved by using a beta gauge CEMS. The commenter dismissed the EPA's technical reservations on these issues as arbitrary speculation. The commenter also stated that PM CEMS are already in successful use by cement plants both in this country and overseas. The commenter further believed that the EPA could resolve these technical issues by amending the PM CEMS Performance Specification rather than by amending the averaging time of the PM standard and changing its compliance basis.

In response, we note first that we do not accept the commenter's legal argument based on section 112(d)(7). Section 112(d)(7) states that "[n]o other emission standard * * * under this section shall be interpreted, construed or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to section 111 of this title, part C or D of this subchapter, or other authority of this chapter or a standard issued under State authority." Although the commenter maintained that this provision unambiguously bars the EPA from amending the promulgated NESHAP to make it less stringent, we disagree. Indeed, it is hard to read the statutory language in such a way. On its face, the provision indicates that a section 112(d) standard does not supplant more stringent standards issued under some authority other than section 112(d). Nor does the commenter's interpretation make sense. It would bar the EPA from amending a section 112(d) standard that was technically deficient or incorrect. This cannot have been Congress' intent when adopting the technology-based section 112(d) MACT regime.[6] Moreover, when Congress adopted anti-backsliding provisions in the CAA, it did so explicitly. See CAA sections 172(e); 110(l); and 193. There is no such explicit language in section 112(d)(7). Thus, the EPA does not read section 112(d)(7) as precluding amendments to MACT standards which result in numerically less stringent standards, provided of course, that such standards are technically justified and otherwise consistent with the requirements of the Act.

The commenter is also mistaken in asserting that sources can simply utilize PM CEMS not correlated to PS 11. The PS 11 requirements apply to all PM CEMS used by a cement kiln. See sections 63.1349(b)(1)(A) and 1350 (b)(1) from the 2010 final rule (75 FR 55057, 55059).[7]

With regard to the technical issues raised by this commenter, the EPA explained in detail at proposal the problems of correlating PM CEMS under PS 11 at cement plants (see 77 FR 42374–42377). These obstacles are not resolvable simply by measuring more often and longer, as the commenter maintains. Extending the duration of the Method 5 test gives this reference method additional opportunity to collect more sample mass, but this is no guarantee that the time added to the test will collect enough particulate mass to resolve detection issues, especially when testing is conducted at the better performing (lower emitting) sources. Longer test runs inherently increase the variability of the PM CEMS data collected during the test, which may cause further difficulties with the

[5] One commenter inaccurately stated that the proposed rule would essentially double the PM standard. As just explained, the existing source floor (and standard) increased from 0.04 30-day average to 0.05 lb/ton clinker 30-day average as a result of removing CISWI kilns. As a not-to-exceed standard, that same level is expressed as 0.07 lb/ton clinker, the higher level reflecting the greater variability involved when basing the standard on the average of the three test runs rather than on 30 days of measurements.

[6] The commenter cites no legislative history to support its reading, nor is EPA aware of any.

[7] It also makes no sense to use PM CEMS not subject to a uniform calibration protocol. The results obtained would not be comparable.

correlation between instrument and reference method. Nor does conducting a higher number of reference method tests resolve the difficulties with PS 11 correlation created by greater uncertainty in the reference method at low levels. Put another way, more tests with high uncertainty and poor correlation do not improve the likelihood of passing PS 11 as there is no expectation of improving the mathematical relationship between the reference test and the instrument. Furthermore, PS 11 section 8.6 requires a minimum number of fifteen tests to develop a correlation curve, with no limit to the maximum number. Considering more than 15 tests when developing the correlation creates much difficulty in developing a precise mathematical relationship. Sources are allowed to discard 5 runs for any reason they wish, but must present at least 15 test runs for the correlation calculation. *Id.* As a source increases the number of test runs beyond 20, any additional runs must be included in the correlation equation and at that point the ability of a source to satisfy PS 11 becomes more hampered with every test run.

The EPA noted that special problems are posed by the size and variability of cement kiln-generated particulate. The EPA also noted that the standard light-scintillation type of PM CEMS would likely encounter higher variability for the same PM concentration, and have difficulty satisfying correlation protocols as a result. The EPA noted that beta gauge CEMS could potentially resolve at least some issues related to cement particle variability but noted further that these devices were largely untested in the cement industry, and none (so far as the EPA is aware) has successfully completed a PS 11 certification. See 77 FR 42375/3. The commenter maintains that the existence of beta gauge CEMS resolves all questions as to their reliability in the cement industry, but the EPA reiterates, as it did at proposal, that there needs to be some assurance of the reliability of that methodology to certify with PS 11 at low levels (as required by this final rule). That information does not presently exist. The commenter states that the EPA is being speculative as to potential difficulties with a different CEMS technology, but relative to Portland cement sources, it would be speculative to assume that beta gauge CEMS would successfully pass a PS 11 certification to reliably and quantifiably measure compliance with the NESHAP, especially at the very low PM levels at some of the sources in the cement source category.

The commenter also maintains that Tapered Element Oscillating Microbalance (TEOM) devices could be used in place of light scintillation PM CEMS. A TEOM is a device that uses a very thin, tapered, element vibrating at a known frequency that has a first principle relationship to the measurement of mass. Particles that impact the element also impact the harmonic vibration of the sensor which can be translated to a measurement of the particle mass. This is a more direct approach to measuring the actual mass of PM in stack gas, and has shown promise to operate very consistently at low levels in laboratory conditions. Several TEOMs are currently used for monitoring ambient PM levels at several non-cement, non-domestic industry installations. TEOMs that are capable of measuring stack gas are not currently available for sale in the U.S., though this may change in future years. Even so, with a monitor capable of more direct mass measurement of PM in stack gas, using PS 11 to certify one against Method 5 may be problematic at low PM concentrations. The EPA currently has no data to assess TEOM capabilities versus Method 5 at very low PM concentrations such as those presented by the better performing sources in this category. Were TEOM instrumentation commercially available, the EPA would need to conduct a re-evaluation of PM CEMS technology that included TEOM data to determine if this instrument could overcome the challenges posed by calibration with Method 5 at the very low PM levels emitted by some of the sources in the cement source category. As just explained, it is not speculation, but rather legitimate engineering caution that makes it appropriate not to require compliance with a rule based on an untested measurement methodology.

The commenter further maintains that rather than amend the standard to change the compliance test methodology and averaging time, the EPA should revise PS 11 instead, evidently assuming that a revision can be done rapidly. The commenter's assumption is mistaken. Performance specification development is a process that takes multiple years and involves data collection on types of technologies, field testing, comparison to reference measurement methodology, workgroup and stakeholder meetings, peer review, rule proposal and public comment period, as well as comment response and final promulgation of the Performance Specification. With the development of PA 12A for Mercury CEMS, the EPA invested a budget in excess of one million dollars to conduct technology and field studies, as well as to refine the analytical techniques and work through stakeholder concerns prior to proposal of the Performance Specification. The process from inception to final promulgation took over 5 years to complete. PS 11, at issue here, was over 3 years in development, from concept to final promulgation, and involved a budget of $250,000. Based on this past history, it is likely to result in a delay of 3 years or more were the EPA to delay promulgation of this final rule until we could undertake the process to research, propose and finalize solutions to PS 11 that may ameliorate some of the issues vis-a-vis the cement industry now present. Furthermore, such a process would not address the issues relating to measurement uncertainties using Method 5 at low PM concentration levels near its detection limit (i.e. below its practical quantitation limit of 3 mg), and so there would remain significant technological hurdles to clear before the EPA could require the use of PM CEMS in respect to this final rule.

The commenter points to PM CEMS use by European cement kilns. This is a misplaced comparison. The European calibration and certification of this instrumentation is completely different than PS 11 requirements developed by the EPA. European monitoring is certified in a laboratory environment, and calibrated on site by the instrument vendor when installed. The EPA has a long history of requiring CEMS installations in the USA to meet more rigorous calibration and performance specification certification through a series of comparisons to reference Method 5 test measurements conducted on the stack with the flue gas matrix at the facility, not in a controlled laboratory. For a PM CEMS, this would be a correlation developed with Method 5 as described in PS 11. The two certification regimes differ greatly in approach and simply adapting European certification standards to USA facilities does nothing to mitigate this difference.

In summary, the EPA has carefully considered the issue and it is our engineering judgment that the PS 11 correlation will not be technically or practically achievable for a significant number of cement kiln sources. This is due to the combination of the low emissions concentrations, PM CEMS measurement uncertainty factors, the variability in composition of cement PM, and need for extraordinarily long test runs to reduce Method 5 uncertainty to a level that provides normal measurement confidence (i.e. greater than the 3 mg practical quantitation level of Method 5), plus the

compounding uncertainties associated with source operational variability. The EPA further recognizes that these problems in developing PS 11 correlations are most likely to adversely affect the lowest emitting sources in the category and are more likely to result in violations of the rule more often for these sources than for sources operating with higher PM emissions. This result would obviously be environmentally counterproductive. We are therefore amending the standard to be based on stack testing, and expressing the standard as a not-to-exceed (i.e., stack test Method 5 or 5I) standard of 0.07 lb/ton clinker.[8]

Additional responses regarding these issues, including responses to issues raised in the comments from industry, are found in sections 3 and 4 of the Response to Comment document, which is found in the docket for this rulemaking.

2. Issues Related to Use of CPMS for Parametric Monitoring

To document continuous compliance with the Method 5 standard (i.e., parametric monitoring designed to monitor proper operation of PM controls), the EPA proposed that PM be monitored continuously using a CPMS. See 77 FR 42376–77. The parametric limit was to reflect the highest of the three method 5 test runs from the stack test, and would be averaged over 30-days. The EPA further proposed corrective action requirements in the event of exceeding the 30-day rolling average parametric limit, and a rebuttable presumption that four such exceedances in a calendar year showed a violation of the emission standard itself.

With respect to the use of CPMS technology, the EPA has recognized that PM CEMS technology cannot meet PS 11 requirements in all Portland cement installations, yet the EPA has also recognized that PM CEMS sensors are more sensitive and better at detecting small differences in PM concentration than other technologies such as opacity monitors (*http://www.epa.gov/ttn/emc/cem/pmcemsknowfinalrep.pdf*) In considering the use of PM CEMS at Portland cement facilities we find that while using PM CEMS technology for continuous quantitative measurement of PM concentration as correlated to Method 5 with PS 11 is frequently not achievable (as stated in the preceding subsection of this preamble), using the same technology for continuous qualitative measurement of PM emissions is practicable in every instance. Given the information we have that shows PM CEMS technology to be more sensitive to in-stack PM concentration differences than opacity monitors and nepheolmeters, the EPA sees a distinct advantage in using these technologies for continuous parametric PM monitoring, rather than measuring some other parameter.

In using a PM CEMS as a CPMS to conduct continuous qualitative monitoring of PM concentration in the stack, we are not interested in specific output information from the instrument (e.g. lbs/ton clinker). We only need to know that PM concentration increases or decreases. The signal output from the instrument need not be correlated to PM concentration through PS 11 trials to achieve this, but rather we can accept the native signal output from the instrument, as is, in milliamps, and track that signal to determine trends in PM emissions. In this final rule we are requiring PM CPMS instruments to employ a 4–20 milliamp output, which is a standard electronic signal output common to many CEMS.[9] With a PM CPMS the milliamp output would not represent an opacity value, but like an opacity analyzer, the milliamps would increase as PM concentration increases and decrease as PM concentration decreases. We can then monitor the milliamp signal while conducting a Method 5 performance test and correlate the average milliamp signal to the average PM concentration during the testing. This relationship is notably coarser in terms of understanding the precise PM concentration in the stack, but the instrument's sensitivity to changing PM concentration in the stack, and its changing milliamp signal output, does not deteriorate and may still be employed to qualitatively monitor PM emissions.

The EPA received numerous comments about our proposed PM CPMS parametric monitoring approach. Industry commenters maintained that sources would have to continually retest unnecessarily, since CPMS measure an increase in PM CPMS values. This increase in PM CPMS values would (or at least, could) denote a modest rise in PM emissions, but actual stack emissions of PM could still be well below the limit. The EPA recognizes this concern as creating additional burden for facilities exhibiting good control of their PM emissions (see section IV.A above), and, therefore, we have modified the process by which a source would establish and comply with their PM CPMS operating limit in this final rule. In doing so we considered scaling options for PM CPMS signals, as they correspond with PM emissions, that were proposed by industry but found the options presented were not protective enough of the emission standard. After extensive analysis (see S. Johnson, memo to docket number EPA–HQ–OAR–2011–0817, ''Establishing an Operating Limit for PM CPMS'', November 2012), we are promulgating a scaling factor of 75 percent of the emission limit as a benchmark. See section IV.A above. As in the proposed rule, every source will need to conduct an annual Method 5 test to determine compliance with the PM emissions limit, and during this testing will also monitor their PM CPMS milliamp output. Sources which emit PM less than 75 percent of their emission limit will be able to scale their PM CPMS milliamp output to determine where their PM CPMS would intersect 75 percent of their allowed PM emissions, and set their operating level at that milliamp output. This alleviates many re-testing concerns for sources that operate well below the emission limit and provides them with greater operational flexibility while still assuring continuous compliance with the PM stack emission standard. It also creates an incentive for sources to select high efficiency PM controls when sources are evaluating potential compliance strategies.

For sources whose Method 5 compliance tests place them at or above 75 percent of the emission standard, their operating level will be the average PM CPMS milliamp output during the three Method 5 test runs. This means their operating level is the milliamp output that correlates to their PM compliance determination, and not the highest average 1 hour run value that was in the proposed rule. Now that we are adopting a scaling factor, we no longer believe that it is also appropriate to establish the parametric limit based on the highest of the three runs (which moreover, could reflect a level higher than the level of the standard). Moreover, as noted below, we believe that on balance the 30 days of averaged

[8] Because the EPA believes that these same issues pertain to measurements of the section 111(b) new source performance standard for modified sources, and because further controls would be both costly and not cost effective (see section V.A.3 below), the EPA is adopting the same amendment for modified new sources under the NSPS.

[9] For example, an opacity instrument uses a series of filters to calibrate the analyzer and produce a "percent opacity" output. Twenty five percent opacity likely correlates to a milliamp value near eight milliamps, or 4 milliamps plus 25 percent of the difference between 4 and 20 milliamps (again, 4 milliamps). Fifty percent opacity would represent a signal near 12 milliamps, and so on, with 20 milliamps representing a signal of 100 percent opacity.

CPMS measurements provides ample operating cushion.

In a recent rule (76 FR 15736, March 21, 2011), the EPA established 75 percent of the limit as a number that allows for compliance flexibility and is simultaneously protective of the emission standard. In this final rule we are utilizing that value so as not to impose unintended and costly retest requirements for the lowest emitting sources and to provide for more cost effective, continuous, PM parametric monitoring across the Portland cement sector. This approach was selected from among many considered as it provides the greatest amount of flexibility while demonstrating continuous compliance for sources which are the lower emitters in the category and is also effective in holding higher emitters to the emission standard. With this parametric monitoring approach in place we expect sources to evaluate control options that provide excellent PM emissions control and provide them greater operational flexibility below the standard.

One commenter maintained that the use of a CPMS for parametric monitoring would be ''egregious'' since the milliamp output of the CPMS allowed a source to select operational parameters of tangential relation to PM emissions and would therefore not provide useful information as to proper PM control. The commenter also stated that monitoring of opacity would be preferable. An industry commenter likewise requested that continuous opacity monitors or bag leak detectors be used rather than CPMS.

The EPA does not agree with these comments. First, the milliamp output of the CPMS reliably and sensitively indicates increasing or decreasing PM concentration in the stack. Where PM controls are failing, the PM CPMS signal will indicate the increasing concentration of PM in the stack. A source will need to monitor the trend from the PM CPMS daily reading to maintain compliance with the 30-day emission standard. Indeed, the EPA has sufficient confidence that four exceedances of the CPMS continuous measurements is a presumptive violation of the emission standard itself. Moreover, the CPMS is considerably more sensitive than an opacity monitor or bag leak detector at detecting fluctuations in PM level. An opacity monitor determines the percent of a light signal that is occluded across the stack diameter. Opacity analyzers operate on a zero to 100 percent scale, meaning they are capable of registering PM that completely occludes the far stack wall from the instrument light source. This amount of PM is roughly equivalent to a complete failure of the emission control device. A properly operating control device will emit five percent opacity or less, which is barely visible to the naked eye and on the low end of the opacity monitor capability. PM emissions that increase opacity two percent at this level may well exceed the emission standard, yet they only mildly deflect the opacity monitor output. This same 2 percent opacity increase is capable of registering changes of several milliamps on a PM CPMS when operating on the scale provided in this final rule. With several decimal fractions available between each milliamp to track signal output, and three or four milliamps representing 1 percent opacity, the PM CPMS has a clear advantage in low PM concentration measurement over continuous opacity monitoring systems. Regarding baghouse leak detectors, the EPA has no information that shows them operating on the same sensitivity level as PM CPMS technology, and we do not require baghouse leak detection systems on sources where PM CPMS are in use for this reason.

Industry commenters objected to the proposal that 4 calendar year exceedances [10] from the parametric limit would be a presumptive violation of the emission standard. Again, the EPA does not agree. First, the EPA may permissibly establish such a presumption by rule, assuming there is a reasonable factual basis to do so. See *Hazardous Waste Treatment Council* v. *EPA,* 886 F. 2d 355, 367–68 (DC Cir. 1989) explaining that such presumptions can legitimately establish the elements of the agency's *prima facie* case in an enforcement action. Second, there is a reasonable basis here for the presumption that four exceedances (i.e. increases over the parametric operating limit) in a calendar year are a violation of the emission standard. The parametric monitoring limit is established as a 30-day average of the averaged test value in the performance test, or the 75th percentile value if that is higher. In either instance, the 30-day averaging feature provides significant leeway to the owner operator not to deviate from the parametric operating level since the 30 measurements will significantly dampen variability in the single measurement (average of three test runs) that produced the parametric value. See 77 FR 42377/2 and sources there cited. The EPA acknowledges that the difference was even greater between the parametric level and the emission standard in the proposed rule (which was based on the highest measured test run). The EPA believes that the 30-day averaging feature plus the 75-percent scaling feature for the lower emitting sources now provides a sufficient operating cushion. See 77 FR 42377.

3. Existing Source Beyond the Floor Determination

The EPA proposed to use the floor levels for PM as the standard, rejecting more stringent standards on the grounds of poor cost effectiveness (after considering non-air environmental impacts and energy implications of a more stringent standard as well). See 77 FR 42376. One commenter argued that the EPA should adopt a beyond the floor standard for PM, maintaining that such a standard was justified under the factors set out in section 112 (d)(2).

The EPA disagrees, and is not adopting a beyond the floor standard. After considering the cost of the emission reductions attributable to such a standard, and the associated non-air and energy impacts of such a standard, the EPA determines that the standard is not ''achievable'' within the meaning of section 112 (d)(2). Specifically, the EPA estimates that a beyond the floor standard set at the level of the original (2010 final rule) standard would only result in 138 tpy—nationwide—of PM reduction (a value not questioned by any of the commenters). See Final Portland Cement Reconsideration Technical Support Document, December 20, 2012. We further estimate that the cost of achieving this modest incremental reduction would be approximately $37 million (the estimated cost savings attributable to the amended PM standard (including savings attributable to ancillary PM controls related to collection of PM from the control of Hg, THC, and HCl). See Final Portland Cement Reconsideration Technical Support Document, December 20, 2012, included in the rule docket, EPA–HQ–OAR–2011–0817. These total costs are high compared to the small nationwide emission reductions, and the cost effectiveness of these reductions is correspondingly high: approximately $268,000 per ton of PM removed. This is significantly higher cost effectiveness for PM than the EPA has accepted in other NESHAP

[10] In the proposed rule, the EPA referred to a measurement higher than the parametric limit as a ''deviation'' and proposed a definition of deviation. See 77 FR 42398. The EPA is not including this terminology in this final rule. The term ''deviation'' is not in the Portland cement NESHAP rules (which date back to 1998), and has not proved necessary in practice. More important, the rule itself states what the consequences of measurements which exceed a parametric limit are (i.e. retesting, and in some instances, a presumptive violation of the emission standard itself), so that no further general regulatory provision (i.e. a generalized definition of 'deviation' or similar term) is necessary.

standards. See 76 FR 15704 (March 21, 2011) (rejecting $48,501 per ton of PM as not cost effective for PM emitted by CISWI energy recovery units); see also 72 FR 53814, 53826 (Sept. 20, 2007) (proposing (and later accepting) cost effectiveness of $10,000 per ton for PM as reasonable in determining Generally Available Control Technology, and noting that the EPA had viewed cost effectiveness only as high as approximately $31,000 per ton as reasonable under its Title II program for mobile sources). A beyond the floor standard at the level of the 2010 standard would also involve slightly higher energy use, although this is not a major factor in EPA's decision. EPA is therefore not adopting a beyond the floor standard for PM at the level of the 2010 standard. A standard even more stringent would likewise not be justified. See 76 FR 54988.[11]

4. New Source PM Standard Under Section 112(d)(3)

One commenter challenged the methodology the EPA used in the 2010 rulemaking to establish the new source floor and standard, maintaining that for new plants, the EPA's floors must reflect the emission level achieved by the single best performing kiln in the category, not the best performing kiln for which the EPA happens to have emissions information. See section 112(d)(3). The EPA did not reopen the methodology by which new source floors for this industry are determined. See 77 FR 42373 n. 3 ("The EPA will not consider comments challenging the data and methodology for the new source standards since these are unchanged from the 2010 rule and the EPA is not reexamining any of these issues.") In any case, if the issue is (against the EPA's view) deemed to be reopened, CAA section 112(d)(3) indicates that new source floors are to be based on "the emission control that is achieved in practice by the best controlled similar source, *as determined by the Administrator*" (emphasis supplied). This language affords considerable discretion for the agency to base the NESHAP new source floors on performance of sources for which the agency has emissions information.

B. Mercury Standard

The EPA explained at proposal that reanalysis of the mercury floor, after removing CISWI kilns, resulted in a floor of 58 lb/MM tons clinker produced—slightly higher than the previously calculated floor and standard of 55 lb/MM tons clinker produced. The EPA further proposed to adopt 55 lb/MM tons clinker produced as a beyond-the-floor standard. See 77 FR 42373. The new source standard was unchanged since the standard was based on the performance of the best performing similar source.

The EPA is adopting the standards as proposed. One commenter challenged the appropriateness of adopting a beyond-the-floor standard, not for the industry as a whole, but for itself. As to this individual plant (Ash Grove, Durkee), the commenter maintained that the cost of attaining the three additional lb/MM ton clinker produced reduction (i.e., the difference between 58 and 55 lb/MM tons clinker produced) was greater than the EPA estimated because it would require more than just additional carbon in an activated carbon injection system to achieve the incremental difference. According to the commenter, they have performed extensive testing and the addition of activated carbon per million actual cubic feet per minute of exhaust gas has little or no impact on mercury emissions. The commenter states that for plants such as Ash Grove's Durkee plant, there is no known add-on control technology at this time that will assure achievement of the standard on a continuous basis.

We note first that the commenter is somewhat over-estimating the incremental reduction of mercury actually needed. To achieve the emission standard, sources will need to operate their processes and controls so that they can achieve the average emissions level used in setting the existing source limit of 55 lb/MM ton—the so-called design level. See e.g. 77 FR 42389/3 (estimating emissions attributable to this final rule based on design levels); see also discussion of design values in section VI.B below. That level is 31.7 lb/MM ton for the standard of 55 lb/MM ton. See 75 FR 54976/3. The average for the 58 lb/MM ton is 34.1 lb/MM ton. The additional reduction needed is therefore 2.4 lb/MM tons, not 3 lb/MM tons as stated by the commenter.

As the EPA has acknowledged repeatedly, due to the high levels of mercury in their limestone, mercury emissions from the Ash Grove Durkee plant are not typical of other plants in the industry. See, e.g. 75 FR 54978–79. As a result, this plant faces a particularly great challenge in meeting the mercury standard, whether the standard is 55 or 58 lb/MM tons. Because of their unique situation, we do not believe that the difficulties this facility is having in meeting the mercury standards can be generalized to the rest of the industry. Section 112(d)(2) of the Act posits an industry-wide standard. Having said this, our cost analysis conducted for the 2009 proposal and 2010 final rule assumed that this plant would have to install multiple control systems in order to meet the limit for mercury. See Docket item EPA–HQ–OAR–2002–0051–3438. Therefore, if in this particular case the activated carbon injection (ACI) system cannot achieve the small additional reductions required, then the facility has other mercury control options available such as further dust shuttling, or treating cement kiln dust to remove mercury. Dust shuttling entails moving dust from within the kiln to other parts of the process and is considered a closed loop process, thereby not causing any waste impacts. In addition, any costs associated with dust shuttling have already been accounted for in the cost estimates the EPA has developed for this particular facility.

The commenter alluded to control performance data that it shared with the EPA. We note that the commenter has provided pilot scale data as part of the 2010 rulemaking (see Docket item EPA–HQ–OAR–2002–0051–2073), but has not provided data on the effects of increasing carbon injection on mercury emissions for a full scale facility. We note that in the electric utility industry, where there is significantly more experience with ACI, it is well established that higher carbon injection rates increase mercury removal (Sjostrom, S.; Durham, M.; Bustard, J. Martin, C.; "Activated Carbon Injection for Mercury Control: Overview", FUEL, 89, 6, 1320 (2010)). There is no data to indicate that ACI systems in the cement industry would behave differently than those in the utility industry. Given the lack of data on the efficacy of increasing carbon injection rates on mercury removal for full scale cement operations, we cannot conclude that increasing carbon injection is not a

[11] The commenter's argument that section 112 (d)(2)'s requirement that the EPA consider "the cost of achieving such emission reduction" limits the EPA to considerations of economic achievability, and not cost effectiveness, is misplaced. See *Husqvarna AB* v. *EPA*, 254 F. 3d 195, 200 (DC Cir. 2001) (cost effectiveness properly considered in evaluating cost of compliance under CAA section 213, a technology-based provision similar to section 112 (d)(2)). The commenter's further argument that the requirement in section 112 (d)(2) for standards to result in "the maximum degree of reduction in emissions of hazardous air pollutants * * * achievable" considering cost and other factors constrains the EPA's ability to consider cost-effectiveness or otherwise balance the statutory factors has likewise been rejected. See *Sierra Club* v. *EPA*, 325 F. 3d 374, 378 (DC Cir. 2003) (the EPA was left with great discretion in determining how to balance such factors when considering technology-based standards which are to result in maximum reductions achievable).

reasonable approach for increasing mercury removal efficiency.

C. Standards for Fugitive Emissions From Open Clinker Storage Piles

The EPA proposed that cement kilns control fugitive emissions from open clinker storage piles, defined at proposal as ''any clinker storage pile that is not completely enclosed in a building or structure''. These piles would be controlled through the use of work practices which minimized emissions by means of (among others) partial enclosure, damping down the pile by chemical or physical means or shielding piles from wind. These work practices were drawn from permits for existing cement kilns, and every cement kiln appears to already be utilizing some type of work practice to minimize fugitive emissions from open clinker storage piles. See 77 FR 42378. Cement kiln sources were allowed to select from among the specified work practices and choose those most suitable for its operations.

For both new and existing sources, the NESHAP is amended to require that one or more of the control measures identified in the rule be used to minimize fugitive dust emissions from open clinker storage piles. The work practices would apply to open clinker storage piles regardless of the quantity of clinker or the length of time that the clinker pile is in existence.

In addition, the owner or operator must include as part of their operations and maintenance plan (required in § 63.1347) the location of their open clinker storage piles and the fugitive dust control measures as specified in this rule that will be implemented to control fugitive dust emissions from open clinker piles. We agree with comments received that the list of allowed work practices reflects all of the available practices documented in cement kiln facility operating permits to control clinker storage pile fugitive emissions. The size, type and duration of a clinker pile may warrant different types of work practices. The final rule requires that one or more of a variety of work practices need to be employed, recognizing that the source will use the work practices that will be effective for the particular piles. Thus, the EPA has revised the list of work practices to be consistent with those listed in the proposal preamble. These are: Use of partial enclosures, using a water spray or fogging system, applying appropriate dust suppression agents, using a wind barrier and using a tarp. Commenters also requested that the EPA allow other work practices if approved by the delegated authority. Our regulations already provide procedures for sources to seek approval of alternative work practices. See section 112(h)(3) as implemented by 40 CFR 63.8(f).

Several industry commenters stated that the definition of clinker pile is problematic as proposed because it was not limited by size or duration. Commenters note that it is not uncommon for small amounts of clinker to be dropped, or to fall off a front-loader onto the ground when being moved from a kiln to a storage location or from such a location to the grinding mill. Because these are small amounts of clinker, it is also not uncommon that these small quantities of clinker will remain where they were dropped and may not be picked up or removed until the necessary manpower becomes available; in some cases this could be multiple days. Another industry commenter noted that because of the short-term duration of temporary clinker stockpiles, the use of work practices similar to those proposed for clinker storage piles is not feasible. The industry trade association suggested the following definition: ''Open clinker storage pile means an outdoor, unenclosed accumulation of clinker on the ground, which contains in excess of 50,000 tons of clinker, and is utilized for a continuous period in excess of 180 days.'' Under this suggested approach, only a clinker storage pile meeting this definition would be subject to the work practice standards.

We are not adopting this approach. We believe that the potential to emit may be different at different sites for a variety of reasons such as weather and traffic conditions. Nor did the commenter provide information indicating that open clinker storage piles of less than 50,000 tons or stored for less than 180 days are unlikely to produce fugitive emissions. Indeed, as a result of weather, traffic or other conditions, smaller piles stored for shorter periods have the evident potential to emit substantial levels of fugitive emissions. Nor is any such uniformly applicable distinction based on duration evident. Clinker piles can be temporary but be replaced by a new pile at the same (or nearby) location a few days later, with no essential difference in fugitive emissions.

Nonetheless, we believe that the commenter is correct that spills are unavoidable, and that work practices designed for non-temporary piles cannot feasibly be applied in such circumstances. The commenter is also correct that work practices used for non-temporary piles would be misapplied to temporary piles attributable to cleaning storage structures. For these reasons, the definition of ''open storage pile'' excludes these types of piles. Specifically, the definition of open clinker storage pile does not include temporary piles of clinker that are the result of accidental spillage or temporary use of outdoor storage while clinker storage buildings are being cleaned. This final rule defines ''temporary'' to mean piles that remain in place for 3 days or less from their generation (3 days accommodating weekend scheduling). This is sufficient time to either pick these spills up (the applicable work practice for these spills) or to cover them to prevent fugitive emissions.

These final amendments will result in a cost savings to the industry as compared to the 2010 rule. As a result of requiring work practices instead of enclosures, we estimate that there will be a savings of $8.25 million annually. See Final Portland Cement Reconsideration Technical Support Document, December 20, 2012, in this rulemaking docket.

D. September 9, 2015, Compliance Date for the Amended Existing Source Standards

The EPA proposed to establish September 9, 2015, as the compliance date for the amended existing source NESHAP standards. The basic reason for the proposed compliance date was that the proposed change in the PM standard made possible different compliance alternatives for all of the stack emission standards, and that it could legitimately take two years from the original compliance date to implement these new compliance strategies. See 77 FR 42385–87. Further, the amended compliance date would apply to all of the stack emission standards due to the interrelatedness of the standards: the mercury, THC and HCl standards all typically involve some element of PM generation and capture and so the controls must be integrated with PM control strategies. Id. at 42386.

The record for this final rule supports the need for the September 9, 2015 compliance date. With respect to PM control, as the EPA explained at proposal, plants now have the option of retaining electrostatic precipitators (ESP) with modification or downstream polishing baghouses, rather than replacing ESP with baghouses. Plants may also size baghouses differently (with or without incorporation of upstream or downstream polishing elements). The various types of sorbent injection strategies to control organics, mercury and HCl, are affected by the PM limits (and vice versa). Based on the facts of this record for this source

category, the type, size and aggressiveness of the controls for these HAP, as well as the PM controls, are not only interdependent but can all change as a result of the amended PM standard. In addition, the amended alternative oHAP standard affords additional compliance alternatives for control of non-dioxin organic HAP, including alternatives to use of Residual Thermal Oxidizers. See generally, Final Portland Cement Reconsideration Technical Support Document, section 3.1, December 2012, in the docket for this rulemaking.

Determining, developing, installing, testing and otherwise implementing a different comprehensive HAP control regime takes time. Specifically, plants will need to conduct engineering studies, determine the most cost-effective control strategy, seek contract bids, purchase equipment, install and test the new equipment. Below is an estimate of a timeline for a cement kiln to undertake these steps.

TIME NEEDED TO PREPARE FOR COMPLIANCE

[Docket item EPA–HQ–OAR–2011–0817–0505–A1]

Steps in preparing for compliance	Time period
New engineering study	January–April 2013.
Selection of technology providers	April–August 2013.
Technology procurement	August–December 2013.
Detailed technology design and final engineering	January–June 2014.
Equipment fabrication and permitting	June–December 2014.
Construction and tying into existing operation	January–May 2015.
Technology commissioning	June–August 2015.

One commenter, sharply opposing any change in compliance date, maintained that all of this reasoning is hypothetical and that such a consequential extension could not legitimately rest on speculation. The EPA disagrees that this analysis is speculative. First, the EPA's engineering judgment is that the changes in the PM standard and alternative oHAP standard, open up different compliance alternatives from those under the 2010 rule. The EPA has indicated what those alternatives can be, and the time needed to determine, purchase, install and test them. Comments from the affected industry are consistent with the EPA's engineering judgment as to the type of different compliance approaches now available for existing sources.

The EPA's engineering determinations as to the time needed for cement kilns to implement a different multi-HAP control strategy here are moreover consistent with the agency's long-standing analysis (i.e. analysis not specific to the cement industry) of the time needed to install multipollutant control systems. See US EPA, Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA–600/R–02/073, October 2002) (cited at 77 FR 42386). Therefore, the EPA estimated that it is normal for the development and implementation of new compliance measures to take between 15–27 months for single control systems, and longer for systems involving multiple controls for HAP and criteria pollutants, as is the case here.

The record to this rule also contains a survey of 92 of the 97 domestic cement kilns currently in operation. These survey results document, on a kiln by kiln basis, alternative engineering strategies now available to these kilns as a result of the amended PM standard and also documents the time each kiln estimates would be needed to carry out these new compliance strategies. See Comments of PCA, Appendix D (EPA–HQ–OAR–2011–0817–0505). For example, kiln B [12] has the option of modifying its ESP system using a hybrid ESP/baghouse filter system, or of using a cyclone upstream of the ESP. Steps needed to implement these possibilities include main stack evaluation, cooler stack testing, and evaluation, vendor/contractor selection, final design, equipment procurement and fabrication, startup and commissioning, and demonstrating compliance. The plant has already commenced some of these steps, but provides reasonable time estimates for why it would take until September 2015 to complete them. Kiln Q [13] expects to be able to retain its ESP system (whereas it could not under the 2010 final rule), but needs to resize its dust conveying system, upgrade the ESP, and utilize a larger activated carbon injection system differently from planned (since an ESP will not capture mercury as would a baghouse). Steps involved in developing and implementing a system include reviewing the structural integrity of the existing ESP, obtaining proposals on ESP upgrades, relocating an existing stack adjacent to the existing ESP, complete stack design, order equipment for ESP upgrades, order a new stack, contract construction, perform necessary construction, modify the ESP as needed, evaluate CEMS performance and conduct stack testing and make any adjustments to the integrated control system. Again, reasonable timelines for carrying out these steps are provided.

Neither the EPA nor the industry has said definitively what each kiln will do and how long it will take. Until the standards are finalized, no such definitive pronouncement is possible. However, the record is quite specific that additional control strategies are now possible; what the range of those new control strategies are; that the strategies are interrelated so that the standards for PM, organics, mercury and HCl are all implicated; and the time needed to carry out the various strategies. Thus, the commenter is mistaken that the record regarding the need for a compliance date of September 2015 is merely conjectural.

The EPA solicited comment on the possibility of a shorter extension for the stack emission standards, noting that by virtue of the 2010 final rule, the industry was not starting from scratch but could already undertake compliance steps. See 77 FR 42386/3. The survey results referred to above confirm that this is the case, since a number of plants (to their credit) indicated that they have taken preliminary steps toward compliance such as conducting stack testing, and testing various control strategies (e.g., survey results for kilns A, F and G). Nonetheless, many commenters made the evident point that this preliminary work could only go so far when there was uncertainty about

[12] For competitiveness reasons, kilns in this survey are identified by letter. The survey results are consistent with the EPA's engineering understanding and judgment, and the EPA has no reason to dispute the overall survey results (although some details may be open to question).

[13] These examples were chosen at random by the EPA from the survey information provided in the comment.

the final standard and uncertainty around which standard would determine their final control strategy. Moreover, even those plants which had begun preliminary compliance steps indicated (with specific timelines provided) that the remaining work would legitimately stretch through the summer of 2015.

This same record refutes those comments maintaining that an even longer compliance extension is needed. Not only is this inconsistent with the EPA's own estimates, but the industry survey results document that no further time is needed. See CAA section 112(i)(3)(A) (compliance with CAA section 112(d) standards to be as expeditious as practicable). Therefore, the EPA is revising the compliance date for existing sources for PM, THC, HCl, and Hg to be September 9, 2015.

However, the EPA is establishing February 12, 2014, as the compliance date for the standards for existing open clinker piles. These standards are not inter-related to the stack emission standards, and so need not be on the same timeline. The work practices we are adopting as the standards reflect practices already in place throughout the entire industry. The time needed to come into compliance consequently is to establish a reporting and recordkeeping apparatus, and in some instances to obtain approval (after appropriate demonstration) to use work practices not enumerated in the standard. The EPA estimates that these various steps should not exceed twelve months. Since section 112(i)(3)(A) requires compliance to be as expeditious as practicable, the EPA is establishing a 12 month compliance period for these standards.

A compliance date for an amended standard must still be "as expeditiou[s] as practicable" and not more than 3 years. We believe a compliance extension is appropriate where, as here, for the stack emission standards, the amended result in a compliance regime differs from the initial rule and additional time is needed to develop, install, and implement the controls needed to meet the amended standard. The EPA has shown that to be the case here, as explained above.

The Sierra Club in its comments also argued that the EPA could not change the 2013 compliance date in the 2010 final rule as a matter of law. The commenter rests this argument on CAA sections 112(d)(7) and 112(i)(3)(A). We have responded above to the argument based on section 112(d)(7). Section 112(d)(7) simply is not an anti-backsliding provision (or, at the least, does not have to be interpreted that way).

CAA Section 112(i)(3)(A) states in relevant part:

"[a]fter the effective date of any emissions standard, limitation or regulation * * * the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard".

In *NRDC* v. *EPA (Plywood MACT)*, 489 F. 3d 1364, 1373–74 (D.C. Cir. 2007) the court held that "only the effective date of Section 112 emissions standards matters when determining the maximum compliance date." 489 F. 3d at 1373 (emphasis original). The EPA, therefore, lacked authority to extend the compliance date when it was only adjusting reporting terms. Id. at 1374. The opinion implies, however, that the EPA may reset the compliance date when the EPA amends the actual standard, as here. If the statute provided an absolute bar on the EPA extending an effective date, there was no reason for the court to distinguish the situation where the EPA amends some ancillary feature of the rule from the situation where the EPA amends the actual standard.[14]

The reason it makes sense for the EPA to have the authority to reestablish a compliance date when it amends a MACT standard is evident. In a technology-based regime like section 112(d), if the technology basis of the standard changes with a change of the standard, it takes time to adopt the revised controls. This result fits the statutory text.

Where the EPA has amended an existing source MACT standard, the compliance date for that amended standard must be as expeditious as practicable, and no later than 3 years from its effective date. Sierra Club argues that the original standard (the one that has been amended) must nonetheless take effect, but that standard no longer exists. It has been amended. Moreover, the result of Sierra Club's approach would force sources to install one technology and rip it out in short order to install another. Congress cannot have mandated this result. See *PCA* v. *EPA*, 655 F. 3d at 189 (staying NESHAP standards for clinker piles—that is, effectively extending their compliance date—because "the standards could likely change substantially. Thus, industry should not have to build expensive new containment structures until the standard is finally determined.")[15] [16] Moreover, in the extreme case where the initial standard was outright technically infeasible by any source (and was amended by the EPA to correct this defect), Sierra Club's reading would leave sources with literally no legitimate compliance option.[17] Technology-based standards simply do not work this way.

[14] Sierra Club maintains that because the revisions to the PM standard leave that standard nearly as stringent as the 2010 standard, all that has effectively changed is the standard's averaging time. Sierra Club likens this situation to the amendments to ancillary provisions like reporting at issue in *Plywood MACT*. This is incorrect. First, as explained in section V.A. above, the standard did increase numerically as a result of removing commercial incinerators from the database. Portland Cement Reconsideration Technical Support Document, June 15, 2012, Docket item EPA–HQ–OAR–2011–0817–0225. Second, although the amended PM standard is relatively as stringent as the 2010 standard (75 FR 54988/2 and 77 FR 42389/3), it nonetheless affords different compliance options for all of the standards, as explained above and in further detail in the Response to Comment document. The standard allows flexibility for those days when emissions increase as a result of normal operating variability, without significantly affecting the long-term average performance for PM and affords different compliance opportunities as a result. Nor does the commenter consider the amendment to the alternative oHAP standard, which amendment likewise affords new compliance opportunities.

[15] In a variant of this argument, Sierra Club maintains that in a situation where the compliance date for an initial existing source MACT standard has not yet passed and the EPA amended that standard to make it more stringent, the EPA would nonetheless leave the predecessor less stringent standard in place and require compliance with it. Although this situation has not arisen, the EPA would presumably be governed by the same principle noted by the *PCA* court: is the technology basis for the standard changing in such a way as to require more time for compliance and in a way that negates the compliance strategy of the initial rule. (Of course, if the compliance date of a standard has already occurred and a standard is later amended, that compliance date would not change retroactively.)

[16] Sierra Club maintains that *PCA* is distinguishable because it involved a standard which the EPA was compelled to change. First, the comment is factually mistaken. The EPA had granted reconsideration of the clinker pile standards but had not indicated that the standards would be amended. See 76 FR 28325/1 (May 17, 2011). Nor did the court indicate that the pile standards must change. Rather, "[b]ecause EPA will now be receiving comments for the first time, the standards *could* likely change substantially." 655 F. 3d at 189 (emphasis supplied). Thus, the court effectively reset the compliance date because of a potential future change in the rule which could result in a compliance regime which differed from that in the 2010 final rule. This is directly parallel to the situation now presented by the amended PM and alternative oHAP standards.

[17] An example is the startup and shutdown standard for HCl in the 2010 final rule. The EPA established this standard as zero on the mistaken assumption that no chlorine could be present in the kiln during there periods. See 76 FR 28325 (granting consideration on this basis). The commenter's approach would leave this technically infeasible standard and its compliance date in place without recourse.

E. Eligibility To Be a New Source Under NESHAP

CAA section 112(a)(4) states that a new source is a stationary source if ''the construction or reconstruction of which is commenced after the Administrator first proposes regulations under this section establishing an emissions standard applicable to such source.'' As we explained previously, there is some ambiguity in the language ''first proposes'' and such language could refer to different dates in different circumstances, such as the first time the Agency proposes any standards for the source category, the first time the Agency proposes standards under a particular rulemaking record for the source category, or the first time the Agency proposes a particular standard.

In the proposed reconsideration rule, the EPA proposed to retain May 6, 2009, as the date which determines new source eligibility and solicited comment on this issue. Industry commenters stated that we should change the date for determining new source status from May 9, 2009 to July 18, 2012, the date of the proposed reconsideration rule. In support, they asserted that they will not know what the final standards are until we finalize the reconsideration rule. We disagree with the commenters' suggestion and are retaining the May 6, 2009 date as the date that determines whether a source is a new source under CAA section 112(a)(4).

As we explained at proposal, it is reasonable to retain the May 6, 2009 date as the date the Agency ''first proposed'' standards for this source category. This is the date that EPA first proposed these standards under this particular rulemaking record. Today's action is a reconsideration action, and although it revises the particulate matter new source standard, it is premised on the same general rulemaking record. It is thus reasonable to view the date EPA ''first proposes'' standards to be the May 2009 date. Further, industry commenters essentially advocate an approach whereby any time the Agency changes a new source standard, in any way, on reconsideration, the new source trigger date would change. Such a result is not consistent with Congress' intent in defining the term ''new source'' in section 112(a)(4), to be the date the Agency ''first proposes'' standards. Furthermore, EPA notes that the new source standards finalized today are ones that will be met, in our view, using the same or similar control technologies as would be used to meet the standards issued in May 2010, and commenters have not disputed this conclusion. See 77 FR 42387.

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

A. What are the affected sources?

As noted in the proposed rule, the EPA estimates that by 2013 there will be 100 Portland cement manufacturing facilities located in the U.S. and Puerto Rico that are expected to be affected by this final rule, and that approximately 5 of those facilities are new greenfield facilities. All these facilities will operate 156 cement kilns and associated clinker coolers. Of these kilns, 23 are CISWI kilns. These have been removed from our data set used to establish existing source floors. Based on capacity expansion data provided by the PCA, by 2013 there will be 16 kilns and their associated clinker coolers subject to NESHAP new source emission limits for PM, mercury, HCl and THC, and 7 kilns and clinker coolers subject to the amended NSPS for nitrogen oxide and SO_2. Some of these new kilns will be built at existing facilities and some at new greenfield facilities.

B. How did the EPA evaluate the impacts of these amendments?

For these final amendments, we determined whether additional control measures, work practices and monitoring requirements would be required by cement manufacturing facilities to comply with the amended rules, incremental to the 2010 final standards (since any other comparison would result in double counting). For any additional control measure, work practice or monitoring requirement we determined the associated capital and annualized cost that would be incurred by facilities required to implement the measures. Finally, we considered the extent to which any facility in the industry would find it necessary to implement any of the additional measures in order to comply with these final amendments. Using this approach, we assessed potential impacts from the proposed revisions.

These final amendments to the 2010 rule are expected to result in lower costs for the Portland cement industry. The final amendment to the PM standard affords alternative, less costly compliance opportunities for existing sources. See section V.D above. These could be utilizing existing PM control devices rather than replacing them (for example, retaining an ESP or a smaller baghouse), or supplementing existing PM control rather than replacing it (putting polishing controls ahead of the primary PM control device, for instance). Compliance strategies for the other HAP, all of which involve some element of PM control, also may be affected. Cost savings from these alternatives could be significant. There are also potential cost savings associated with the amended oHAP alternative standard (which now may be a viable compliance alternative for some sources since issues of reliable analytic measurement have been resolved). Following proposal, industry submitted kiln specific information on likely changes in compliance strategy resulting from the proposed amendments so that we are now better able to estimate potential savings resulting from the final amendments. Based on an industry survey of 18 Portland cement facilities (20 kilns) after proposal (see Docket item EPA–HQ–OAR–2011–0817–0505, Appendix D), it appears that the amendments may have the following effects, which may result in savings in capital and annual costs associated with implementing control technologies for these pollutants:

- Regenerative thermal oxidizers (RTO) may not need to be installed due to the amended oHAP alternative.
- Carbon injection rates may be lowered or not required for THC control.
- Existing PM controls (ESP and baghouse) may not need to be replaced, but may instead be upgraded.
- Additional PM controls may not have to be implemented.
- Polishing and hybrid filter configurations may be implemented instead of total replacements.

There are also certain costs, and cost savings, associated with other provisions of the final amendments. There may be a difference in costs of stack testing for PM and use of a CPMS, rather than use of a PM CEMS. In addition, there are cost savings when changing from a PM CEMS compliance demonstration to a CPMS demonstration. For example as part of the PS 11 calibration requirements, a minimum of 15 Method 5 test runs are required to develop a correlation curve, with no limit to the maximum number of test runs. Omitting the need for these multiple test runs will save the facility a minimum of $20,000 per kiln (each Method 5 test costs $5,000). At a savings of $20,000 per kiln, nationwide savings for 133 new and existing kilns, would be $2.7 million per year. However, the CPMS is the same type of device as a PM CEMS, so the capital cost of the CPMS would not be significantly different than the CEMS device.

The final revisions to the alternative organic HAP standard (from 9 ppm to 12 ppm, reflecting the analytic method practical quantitation limit) would allow more sources to select this compliance alternative and demonstrate compliance without needing to install

very expensive and energy-intensive RTO. In addition, providing parametric monitoring flexibilities (not present in the 2010 final rule) will provide lower costs for the better-performing sources in the industry. See section IV.B above. We have quantified these savings (see Final Portland Cement Reconsideration Technical Support Document, December 20, 2012, Section 3).

The revisions to the standard for open clinker storage piles codify current fugitive dust control measures already required by most states, so no impacts are expected. These final standards would be significantly less expensive than the controls for open piles in the 2010 final rule, which required enclosures in all instances. We estimate that the savings to industry over the 2010 rule will be $8.25 million annually. See Final Portland Cement Reconsideration Technical Support Document, December 20, 2012, in this rulemaking docket.

We have estimated the additional industry cost associated with the affirmative defense to civil penalties provisions. We estimate the additional cost is $3,258 per year for the entire industry. See Supporting Statement in the docket.

One of the final revisions would allow sources that control HCl with dry scrubbers to use periodic performance testing and parametric monitoring rather than monitoring compliance with an HCl CEMS. This will provide those sources with additional flexibility in complying with the HCl standard.

The revision to the alternative PM emissions limit provisions merely recognizes that sources other than the clinker cooler may combine their exhaust with the kiln exhaust gas and corrects the equation for calculating the alternative limit. Therefore, there should be no impacts from this revision.

The amendments provide for work practices rather than numerical standards during periods of startup and shutdown. The work practice standards reflect common industry practices, so there should be no costs associated with them. There should also be substantial savings associated with the work practices.

At an annual cost of about $51,000 per year ($22,800 per Method 30B test for mercury + $8,000 per year for Method 25A test for THC + $20,000 per year for Method 321 test for HCl), the final revisions for new testing and monitoring of coal mills that use kiln exhaust gases to dry coal and exhaust through a separate stack are not expected to have significant impacts.

The revisions would make existing kilns that undergo a modification, as defined by NSPS, subject to a PM standard of 0.07 lb/ton clinker, 3-run average. There may be less costly compliance alternatives under the amended standard, similar to alternatives available under the amended existing source NESHAP for PM.

C. What are the air quality impacts?

In these final amendments, emission limits for mercury, THC and HCl are unchanged from the 2010 rule. Thus, there is no change in emissions from the 2010 rule for these HAP and HAP surrogates. The alternative HAP organic standard is being amended to 12 ppm, which is the analytic method practical quantitation limit based on the performance test method detection limit of 4 ppm. The impact on emission levels due to this change is not clear since measuring below the quantitation limit does not yield a value with enough certainty to represent the actual level. Thus, a measurement below 12 ppm could very well actually be 12 ppm or something less. For PM, the limit for existing sources changes from 0.04 lb/ton clinker 30-day average to 0.07 lb/ton clinker based on stack testing. The PM limit for new sources also changed: To 0.02 lb/ton clinker stack test from 0.01 lb/ton clinker 30-day average. The final changes in the PM standards, while not significant in absolute terms, may result in a small increase in total nationwide emissions by allowing slightly more variability, although, as noted at proposal, we estimate that design values will be essentially identical under the 2010 and this final standard. 77 FR 42389. As explained in the impacts analysis for the 2010 rule (see Docket item EPA–HQ–OAR–2002–0051–3438), emission reductions were estimated by comparing baseline emissions to the long-term average emissions of the MACT floor kilns. As a practical matter, plants operate to comply with this lower average emissions level (the so-called design level), rather than the emissions limit, so that on those days where there is normal operating variability they do not exceed the emissions limit. See 77 FR 42386–87. Under the 2010 rule, the average PM emissions from the existing floor kilns were 0.02296 lb/ton clinker. Under the amended standard, the average PM emissions of the existing floor kilns is calculated to be 0.02655 lb/ton clinker although, as noted, this difference is less than the normal analytic variability in PM measurement methods and so must be viewed as directional rather than precisely quantitative. The average emissions for new kilns did not change as we believe new sources will have to adopt identical control strategies as under the promulgated standards. We, therefore, are not estimating an emission increase from new kilns. For existing kilns, with an increase in PM emissions under this final rule of 0.00359 lb/ton clinker compared to the 2010 rule, nationwide emissions of PM would increase by 138 tons per year ($0.00359 \times 76{,}664{,}662/2000$). Thus, the EPA estimates that the main effect of this final rule for PM will be to provide flexibility for those days when emissions increase as a result of normal operating variability, but would not significantly alter long-term average performance for PM. Nonetheless, as explained in section V.D above, this change does allow for changes in compliance strategies in the form of types, sizes and sequencing of treatment trains.

Emission reductions under the 2010 rule and this final rule, in 2015, are compared in Table 4.

TABLE 4—COMPARISON OF NATIONWIDE PM EMISSIONS FROM 2010 RULE TO FINAL RULE IN 2015

	Kiln type	2010 rule	Final rule	Increment
Emissions limit (lb/ton clinker	Existing	0.04 (30-day average with a CEMS).	0.07 (3-run stack test)	NA
MACT average emissions for compliance (lb/ton clinker.	Existing	0.02296	0.02655	0.00359
2010 baseline emissions (CISWI kilns removed) (tons/yr).		11,433	11,433	NA
Nationwide emissions reduction (tons/yr)	Total	10,540	10,402	−138

One commenter noted that the compliance extension will result in two additional years of HAP emissions at pre-standard levels, noting especially the emission of PM, noting further that fine PM ($PM_{2.5}$) is causally associated with mortality and serious morbidity effects at a population level. See, e.g., 77 FR 38909 (June 29, 2012). We note first that these rules are technology-based, not risk-based, and that there are compelling reasons to amend the PM standard and to establish new compliance dates for existing sources as a result of technological limitations with the 2010 rule PM standard, and the new compliance opportunities afforded as a result of the amendment to that standard. See section V.D above. We also question the commenter's premise that all of the predicted emission reductions and benefits would accrue if the existing source CEM-based PM standards took effect in September 2013. As explained at length in section V.A above and in other comment responses, PM CEMS would not reliably measure the level of the PM standard in many instances. One cannot assume the full range of emission reductions (and consequent health benefits) would accrue in the real world if the emission measurements themselves are uncertain. Thus, in a meaningful sense, today's amendments result in a regime where the required emission reductions will be reliably measured, so that the rule's health benefits will reliably occur.

D. What are the water quality impacts?

At proposal, we believed that none of the amendments being proposed would have significant impacts on water quality and that to the extent that the revision affecting dry caustic scrubbers encourages their use, some reduction in water consumption may occur although we had no information upon which to base a quantified estimate. We received no comments questioning this assessment. Further, in reviewing the industry survey information on the impacts of the proposed changes, only 1 of the 20 kilns for which information was provided was considering the addition of a wet scrubber, although it was also evaluating a dry scrubber (see docket item EPA–HQ–OAR–2011–0817–0505, Appendix D, kiln S). Therefore, we continue to believe that these final amendments will not significantly impact water quality.

E. What are the solid waste impacts?

None of the amendments being finalized with this final rule are expected to have any solid waste impacts.[18]

F. What are the secondary impacts?

Indirect or secondary air quality impacts include impacts that will result from the increased electricity usage associated with the operation of control devices as well as water quality and solid waste impacts (which were just discussed) that will occur as a result of these amendments. Because we are finalizing revisions that slightly reduce the stringency of the existing source emission limits for PM from the promulgated 2010 limits, we project that some facilities will alter their strategy for complying with the standards for the four pollutants to achieve compliance at a lower cost than possible under the original standard. The survey results discussed in section V.D above confirm the EPA's engineering judgment. Other facilities in the survey that were not able to meet the THC limit or the alternative organic HAP limit in the 2010 rule were considering the installation of RTO. Because some of these facilities may now meet the limit without the installation of an RTO, we have estimated a reduction of 24,702 tons per year less CO_2 emissions being emitted to the atmosphere (equivalent to 2 less RTO's being installed). As a result of the organic HAP limit being revised from 9 ppm to 12 ppm, these sources responded that they now had other less costly alternatives. The additional compliance time was also cited as a factor that would gives sources the additional time they needed to consider other HAP control alternatives to RTO. As the industry survey highlights, these types of determinations will be made for each facility based on site-specific characteristics such as process type, equipment age, existing air pollution controls, raw material and fuel characteristics, economic factors and others. In general, this survey indicates that the combination of the revised limits for PM and organic HAP as well as the September 2015 compliance date will give sources the opportunity to develop less costly and less aggressive compliance strategies. We do not have enough information to quantify the impact of overall secondary impacts, (with the exception of the CO_2 reductions noted above), but we believe the impacts would in fact be reduced relative to the 2010 rule since less energy is expected to be needed for facilities that can retain and upgrade their current controls, instead of for example, installing additional controls in series.

G. What are the energy impacts?

As discussed in the preceding section, because of the final revisions to the PM emission limits, the organic HAP limits and the compliance date extension, some facilities will develop more cost effective and less energy intensive compliance strategies. For three of the facilities (five kilns) that were part of the industry survey, all five kilns required significant changes to meet the 2010 THC standard, in part because they were not pursuing the alternative organic HAP alternative standard due to analytic measurement uncertainties. See docket item EPA–HQ–OAR–2011–0817–0505, Appendix D (kilns A, C and D, and F and G). Prior to the proposed revisions, all five of the kilns were considering RTO as a control option as well as other options including catalytic ceramic filtration, a relatively new technology and as yet, not completely demonstrated technology for the cement industry. In response to the survey of what changes, if any, the facilities would make in response to the proposed revisions, all three facilities indicated that the amended organic HAP limit or the September 2015 compliance date allowed them to consider the use of less capital intensive alternatives and to continue testing alternatives for THC reduction other than the highly energy-intensive RTO for the five kilns involved. Although we cannot accurately predict for the entire industry the extent to which these site-specific compliance strategies may affect energy demands, the industry survey results indicate a trend toward less energy intensive strategies than RTO, and as noted above, we predict a reduction in CO_2 emissions due to less energy use as a result of two fewer kilns installing RTOs.

H. What are the cost impacts?

Under the cost scenario discussed above, we estimate that there could be savings of approximately $52 million associated with alternative compliance strategies for meeting amended PM standards, making corresponding adjustments in compliance strategies for the organic HAP and requiring work practice for open clinker storage piles. Table 5 summarizes the costs and emissions reductions of this final action.

[18] Although dust shuttling is likely to be one element of mercury compliance strategy, the amount of dust shuttling would not increase incremental to the 2010 final rule since the standards for new and existing sources are the same in the 2010 final rule and these amendments. Moreover, as explained in section V.B above, even with respect to the high mercury feed source, dust shuttling entails moving dust from within the kiln to other parts of the process and is considered a closed loop process, thereby not causing any waste impacts.

TABLE 5—SUMMARY OF THE COSTS AND EMISSION REDUCTIONS OF THE FINAL AMENDMENTS TO THE PORTLAND CEMENT MANUFACTURING INDUSTRY NESHAP RELATIVE TO THE 2010 RULE[a b c d e]

Proposed amendment	Annualized cost	PM emissions reduction 2010 rule	PM emissions reduction 2012 rule	Emission change tpy
Revised PM, oHAP standard	($42.2 million)[f]	10,540 tons	10,402 tons	138 increase.
Replace PM CEMS with PM CPMS	($2.7 million)	0.		
Coal Mill Testing	$1.3 million	0.		
Open clinker storage pile work practices	($8.25 million)	0.		
Total	($51.85 million).			

[a] Parentheses indicate cost savings. All costs are in 2005 dollars.
[b] We also estimate that there will be a one-time cost of $25,000 for each facility to revise their operation and maintenance plan to include procedures to minimize emissions during periods of startup and shutdown.
[c] Emissions reductions are the total once full compliance is achieved in 2015.
[d] Full compliance costs will not occur until September 9, 2015.
[e] Note emission reductions published in the 2010 rule included CISWI kilns, but the reductions in this table reflect reductions since CISWI kilns were removed from the database.
[f] Includes cost savings due to revised PM standard.

The cost information in Table 5 is in 2005 dollars at a discount rate of 7 percent. The EPA did not have sufficient information to quantify the overall change in benefits or impacts in emissions for 2013 to 2015.

With regard to the coal mill monitoring requirements in this action, sources with integral coal mills that exhaust through a separate exhaust would potentially incur a capital cost of $36,000 to install a continuous flow meter. The annualized cost of a flow meter is $11,000. Because this final rule allows the use of maximum design flow rate instead of installing flow meters, we believe that most facilities will take advantage of this and will not incur these costs. Annual testing at these coal mills for mercury, THC and HCl will cost about $51,000 ($22,800 per Method 30B test for mercury + $8,000 per year for Method 25A test for THC + $20,000 per year for Method 321 test for HCl). Using information supplied by the industry (see docket item EPA–HQ–OAR–2011–0817–0612), approximately 26 facilities would be affected by these requirements for an annual cost of $1.3 million. Costs for coal mills to meet the PM limits for this NESHAP are not included, since all equipment and monitoring are in place to meet requirements of Subpart Y and thus are not considered additional costs.

With the final change to PM CPMS instead of CEMS, it is estimated that the elimination of the PS correlation tests will result in a savings of $20,000 per kiln.

I. What are the health effects of these pollutants?

In this section, we provide a qualitative description of benefits associated with reducing exposure to $PM_{2.5}$, HCl and mercury. Controls installed to reduce HAP would also reduce ambient concentrations of $PM_{2.5}$ as a co-benefit. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and morbidity from cardiovascular and respiratory illnesses. Researchers have associated $PM_{2.5}$ exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009).[19] When adequate data and resources are available and a regulatory impact analysis (RIA) is required, the EPA generally quantifies several health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA, 2011).[20] These health effects include premature mortality for adults and infants, cardiovascular morbidities such as heart attacks, hospital admissions and respiratory morbidities such as asthma attacks, acute and chronic bronchitis, hospital and emergency department visits, work loss days, restricted activity days and respiratory symptoms. Although the EPA has not quantified certain outcomes including adverse effects on birth weight, pre-term births, pulmonary function and other cardiovascular and respiratory effects, the scientific literature suggests that exposure to $PM_{2.5}$ is also associated with these impacts (U.S. EPA, 2009). $PM_{2.5}$ also increases light extinction, which is an important aspect of visibility (U.S. EPA, 2009).

HCl is a corrosive gas that can cause irritation of the mucous membranes of the nose, throat and respiratory tract. Brief exposure to 35 ppm causes throat irritation, and levels of 50 to 100 ppm are barely tolerable for 1 hour.[21] The greatest impact is on the upper respiratory tract; exposure to high concentrations can rapidly lead to swelling and spasm of the throat and suffocation. Most seriously exposed persons have immediate onset of rapid breathing, blue coloring of the skin and narrowing of the bronchioles. Exposure to HCl can lead to RADS, a chemically- or irritant-induced type of asthma. Children may be more vulnerable to corrosive agents than adults because of the relatively smaller diameter of their airways. Children may also be more vulnerable to gas exposure because of increased minute ventilation per kilograms and failure to evacuate an area promptly when exposed. HCl has not been classified for carcinogenic effects.[22]

Mercury in the environment is transformed into a more toxic form, methylmercury (MeHg). Because mercury is a persistent pollutant, MeHg accumulates in the food chain, especially the tissue of fish. When people consume these fish, they consume MeHg. In 2000, the National

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

[20] U.S. Environmental Protection Agency (U.S. EPA). 2011. Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States. Office of Air and Radiation, Research Triangle Park, NC. Available on the Internet at *http://www.epa.gov/airtransport/pdfs/FinalRIA.pdf.*

[21] Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Hydrogen Chloride. Atlanta, GA: U.S. Department of Health and Human Services. Available online at *http://www.atsdr.cdc.gov/mmg/mmg.asp?id=758&tid=147#bookmark02.*

[22] U.S. Environmental Protection Agency (U.S. EPA). 1995. Integrated Risk Information System File of Hydrogen Chloride. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at *http://www.epa.gov/iris/subst/0396.htm.*

Academy of Science (NAS) Study was issued which provides a thorough review of the effects of MeHg on human health (National Research Council (NRC), 2000).[23] Many of the peer-reviewed articles cited in this section are publications originally cited in the MeHg Study. In addition, the EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NRC in 2000.

In its review of the literature, the NAS found neurodevelopmental effects to be the most sensitive and best documented endpoints and appropriate for establishing an oral reference dose (RfD) (NRC, 2000); in particular NAS supported the use of results from neurobehavioral or neuropsychological tests. The NAS report noted that studies in animals reported sensory effects as well as effects on brain development and memory functions and support the conclusions based on epidemiology studies. The NAS noted that their recommended endpoints for an RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: ''The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school.''

The NAS summarized data on cardiovascular effects available up to 2000. Based on these and other studies, the NRC concluded that ''Although the data base is not as extensive for cardiovascular effects as it is for other end points (i.e. neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals.'' The NRC also stated that ''additional studies are needed to better characterize the effect of methylmercury exposure on blood pressure and cardiovascular function at various stages of life.''

Additional cardiovascular studies have been published since 2000. The EPA did not to develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail mercury levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

The Mercury Study[24] noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS concluded that evidence that human exposure to MeHg caused genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajós River region in Brazil (Amorim et al., 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes; as well as effects on chromosomes.[25] Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those seen in the Faroes and Seychelles populations.

Although exposure to some forms of mercury can result in a decrease in immune activity or an autoimmune response (ATSDR, 1999), evidence for immunotoxic effects of MeHg is limited (NRC, 2000).[26]

Based on limited human and animal data, MeHg is classified as a ''possible'' human carcinogen by the International Agency for Research on Cancer (IARC, 1994) and in Integrated Risk Information System (IRIS) (U.S. EPA, 2002).[27][28] The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between mercury exposure and overall cancer incidence, although a few studies have shown an association between mercury exposure and specific types of cancer incidence (e.g., acute leukemia and liver cancer) (NRC, 2000).

There is also some evidence of reproductive and renal toxicity in humans from MeHg exposure. However, overall, human data regarding reproductive, renal and hematological toxicity from MeHg are very limited and are based on either studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

VII. Statutory and Executive Order Reviews

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

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a ''significant regulatory action'' because it raises novel legal or policy issues. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action. An RIA was prepared for the September 2010 final rule and can be found at: *http://www.epa.gov/ttn/ecas/regdata/RIAs/portlandcementfinalria.pdf. http://www.epa.gov/ttn/ecas/regdata/RIAs/portlandcementfinalria.pdf.*

B. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501, *et seq.*

The Information Collection Request (ICR) document prepared by the EPA has been assigned the EPA ICR number 1801.11 for the NESHAP; there are no additional recordkeeping and reporting requirements for the NSPS. The information requirements are based on notification, recordkeeping and reporting requirements in the NESHAP

[23] National Research Council (NRC). 2000. *Toxicological Effects of Methylmercury.* Washington, DC: National Academies Press.

[24] U.S. Environmental Protection Agency (U.S. EPA). 1997. *Mercury Study Report to Congress,* EPA–HQ–OAR–2009–0234–3054. December. Available on the Internet at *http://www.epa.gov/hg/report.htm.*

[25] Amorim, M.I.M., D. Mergler, M.O. Bahia, H. Dubeau, D. Miranda, J. Lebel, R.R. Burbano, and M. Lucotte. 2000. Cytogenetic damage related to low levels of methyl mercury contamination in the Brazilian Amazon. An. Acad. Bras. Science. 72(4): 497–507.

[26] Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological Profile for Mercury. U.S. Department of Health and Human Services, Public Health Service, Atlanta, GA.

[27] U.S. Environmental Protection Agency (EPA). 2002. Integrated Risk Information System (IRIS) on Methylmercury. National Center for Environmental Assessment. Office of Research and Development. Available online at *http://www.epa.gov/iris/subst/0073.htm.*

[28] International Agency for Research on Cancer (IARC). 1994. IARC Monographs on the Evaluation of Carcinogenic Risks to Humans and their Supplements: Beryllium, Cadmium, Mercury, and Exposures in the Glass Manufacturing Industry. Vol. 58. Jalili, H.A., and A.H. Abbasi. 1961. Poisoning by ethyl mercury toluene sulphonanilide. Br. J. Indust. Med. 18(Oct.):303–308 (as cited in NRC 2000).

General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emissions standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

We are finalizing new paperwork requirements for the Portland Cement Manufacturing source category in the form of a requirement to incorporate work practices for periods of startup and shutdown and fugitive dust control measures for clinker piles into their existing operations and maintenance plan.

This final rule also includes new paperwork requirements for recordkeeping of malfunctions, as described in 40 CFR 63.454(g) (conducted in support of the affirmative defense provisions, as described in 40 CFR 63.456).

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

The EPA is adding the paperwork and recordkeeping associated with the affirmative defense to civil penalties for malfunctions to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to the ICR that show what the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports and records for any individual incident, including the root cause analysis, totals $3,258, and is based on the time and effort required of a source to review relevant data, interview plant employees and document the events surrounding a malfunction that has caused a violation of an emissions limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense.

Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of violations caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we expect the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small. For this reason, we estimate no more than two such occurrences per year for all sources subject to subpart LLL over the 3-year period covered by this ICR. We expect to gather information on such events in the future and will revise this estimate as better information becomes available.

We estimate 86 facilities will be subject to all final standards. The remaining 14 facilities will only be subject to the open clinker pile standards in this action. The annual monitoring, reporting and recordkeeping cost for this source (averaged over the first three years after the effective date of the standards) for these amendments to subpart LLL is estimated to be $352,814 per year for the industry. This includes 496 labor hours per year at a total labor cost of $47,806 per year, and total non-labor capital and operation and maintenance costs of $305,008 per year. This estimate includes reporting and recordkeeping associated with the requirements for open clinker storage piles. The total burden to the federal government (averaged over the first three years after the effective date of the standard) as a result of these amendments is estimated to be 263 hours per year at a total labor cost of $11,885 per year. Burden is defined at 5 CFR 1320.3(b).

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

C. Regulatory Flexibility Act

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

For purposes of assessing the impact of this rule on small entities, small entity is defined as: (1) A small business whose parent company has no more than 750 employees based on the size definition for the affected NAICS code (327310), as defined by the Small Business Administration size standards; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

We estimate that 3 of the 26 existing Portland cement entities are small entities and comprise 3 plants. After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Of the three affected small entities, all are expected to incur an annual compliance cost of less than 1.0 percent of sales to comply with these amendments to the 2010 final rule (reflecting potential controls on piles, which are likely to have lower cost when compared to the 2010 rule requirements because these plants already have requirements for

control of open clinker storage piles in their title V permits).

Although this final rule will not have a significant economic impact on a substantial number of small entities, the EPA nonetheless adopted amendments which should reduce the impact of this final rule on small entities. For example, we are expanding the provision that allows periodic HCl performance tests as an alternative to HCl CEMS for sources equipped with wet scrubbers to also apply to those sources that use dry scrubbers. This final rule also adds an option for sources using wet or dry scrubbers for HCl control to use SO_2 as a monitored parameter. If these sources already have a CEMS for SO_2, then this will provide operational flexibility.

D. Unfunded Mandates Reform Act

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local and tribal governments, in the aggregate, or the private sector in any one year. As discussed earlier in this preamble, there is an actual savings to the industry of $52 million per year. Thus, this final rule is not subject to the requirements of section 202 and 205 of the UMRA. This final action is also not subject to the requirements of section 203 of the UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This final action contains no requirements that apply to such governments, imposes no obligations upon them, and will not result in expenditures by them of $100 million or more in any one year or any disproportionate impacts on them.

E. Executive Order 13132: Federalism

This final action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. None of the affected facilities are owned or operated by State governments. Thus, Executive Order 13132 does not apply to this action.

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

This action may have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). The EPA is aware of one tribally owned Portland cement facility currently subject to subpart LLL and that will be subject to this final rule. The provisions of this final rule are not expected to impose new substantial direct compliance costs on Tribal governments since the same control technologies that are necessary under the current NESHAP will be needed to meet the final emissions limits. The EPA has tried to reduce the impact of this final rule on Tribal owned facilities. For example, we are expanding the provision that allows periodic HCl performance tests as an alternative to HCl CEMS for sources equipped with wet scrubbers to also apply to those sources that use dry sorbent injection (i.e., dry scrubbing systems). This final rule adds an option for sources using wet or dry scrubbers for HCl control to use SO_2 as a monitored parameter. If these sources already have a CEMS for SO_2, then this will provide operational flexibility.

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

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

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

This final action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The amendments do not require the use of additional controls as compared to the 2010 rule and may allow the industry to reduce its cost of compliance by increasing the industry's flexibility to institute different and less costly control strategies than under the 2010 rule.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law No. 104–113 (15 U.S.C. 272 note), directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable VCS.

This final rulemaking does not involve technical standards. Therefore, the EPA is not considering the use of any voluntary consensus standards.

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

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

An analysis of demographic data was prepared for the 2010 final rule and can be found in the docket for that rulemaking (See docket item EPA–HQ–OAR–2002–0051–3415). The impacts of the 2010 rule, which assumed full compliance, are expected to be unchanged as a result of this action. Therefore, beginning from the date of full compliance, the EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income populations. In addition, the full benefits of this final rule will not result until 2015 due to the final amended compliance date but the demographic analysis showed that the average of populations in close proximity to the sources, and thus most likely to be affected by the sources, were similar in demographic composition to national averages.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that, before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the

Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This final rule will be effective on February 12, 2013.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Reporting and recordkeeping requirements.

Dated: December 20, 2012.

Lisa P. Jackson,

Administrator.

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

PART 60—[AMENDED]

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

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

Subpart F—[AMENDED]

■ 2. Section 60.61 is amended by adding paragraphs (e) and (f) to read as follows:

§ 60.61 Definitions.

* * * * *

(e) *Excess emissions* means, with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

(f) *Operating day* means a 24-hour period beginning at 12:00 midnight during which the kiln operates at any time. For calculating rolling 30-day average emissions, an *operating day* does not include the hours of operation during startup or shutdown.

* * * * *

■ 3. Section 60.62 is amended by:

■ a. Removing and reserving paragraph (a)(1)(i), revising paragraph (a)(1)(ii) and adding paragraph (a)(1)(iii);

■ b. Removing and reserving paragraph (a)(2);

■ c. Revising paragraphs (b)(1)(i) and (ii);

■ d. Removing paragraph (b)(2);

■ e. Redesignating paragraphs (b)(3) and (4) as (b)(2) and (3);

■ f. Revising newly designated paragraph (b)(3); and

■ g. Revising paragraph (d).

The revisions read as follows:

§ 60.62 Standards.

(a) * * *

(1) * * *

(ii) 0.02 pound per ton of clinker if construction or reconstruction of the kiln commenced after June 16, 2008.

(iii) Kilns that have undergone a modification may not discharge into the atmosphere any gases which contain PM in excess of 0.07 pound per ton of clinker.

* * * * *

(b) * * *

(1) * * *

(i) 0.02 pound per ton of clinker if construction or reconstruction of the clinker cooler commences after June 16, 2008.

(ii) 0.07 pound per ton of clinker if the clinker cooler has undergone a modification.

* * * * *

(3) If the kiln has a separated alkali bypass stack and/or an inline coal mill with a separate stack, you must combine the PM emissions from the bypass stack and/or the inline coal mill stack with the PM emissions from the main kiln exhaust to determine total PM emissions.

* * * * *

(d) If you have an affected source subject to this subpart with a different emissions limit or requirement for the same pollutant under another regulation in title 40 of this chapter, you must comply with the most stringent emissions limit or requirement and are not subject to the less stringent requirement.

■ 4. Section 60.63 is amended by:

■ a. Revising paragraphs (b)(1)(i) and (ii);

■ b. Adding paragraph (b)(1)(iii);

■ c. Revising paragraphs (b)(2) and (3);

■ d. Removing paragraph (b)(4);

■ e. Revising paragraphs (c) through (f);

■ f. Revising paragraph (g) introductory text;

■ g. Revising paragraph (g)(2);

■ h. Revising paragraph (h) introductory text;

■ i. Revising paragraphs (h)(1) and (6);

■ j. Revising paragraph (h)(7) introductory text;

■ k. Revising paragraph (h)(8) introductory text;

■ l. Revising paragraph (h)(9);

■ m. Revising paragraph (i) introductory text; and

■ n. Revising paragraph (i)(1) introductory text and (i)(1)(i).

The revisions and addition read as follows:

§ 60.63 Monitoring of operations.

* * * * *

(b) * * *

(1) * * *

(i) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates of the amount of clinker produced in tons of mass per hour. The system of measuring hourly clinker production must be maintained within ±5 percent accuracy or

(ii) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates of the amount of feed to the kiln in tons of mass per hour. The system of measuring feed must be maintained within ±5 percent accuracy. Calculate your hourly clinker production rate using a kiln specific feed-to-clinker ratio based on reconciled clinker production rates determined for accounting purposes and recorded feed rates. This ratio should be updated monthly. Note that if this ratio changes at clinker reconciliation, you must use the new ratio going forward, but you do not have to retroactively change clinker production rates previously estimated.

(iii) For each kiln operating hour for which you do not have data on clinker production or the amount of feed to the kiln, use the value from the most recent previous hour for which valid data are available.

(2) Determine, record, and maintain a record of the accuracy of the system of measuring hourly clinker production rates or feed rates before initial use (for new sources) or by the effective compliance date of this rule (for existing sources). During each quarter of source operation, you must determine, record, and maintain a record of the ongoing accuracy of the system of measuring hourly clinker production rates or feed rates.

(3) If you measure clinker production directly, record the daily clinker production rates; if you measure the kiln feed rates and calculate clinker production, record the daily kiln feed and clinker production rates.

(c) *PM Emissions Monitoring Requirements.* (1) For each kiln or clinker cooler subject to a PM emissions limit in § 60.62, you must demonstrate compliance through an initial performance test. You will conduct your performance test using Method 5 or Method 5I at appendix A–3 to part 60 of this chapter. You must also monitor continuous performance through use of

a PM continuous parametric monitoring system (PM CPMS).

(2) For your PM CPMS, you will establish a site-specific operating limit. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit equivalent to 75 percent of the standard. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit. You will use the PM CPMS to demonstrate continuous compliance with your operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(ii) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(iii) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(3) Determine your operating limit as specified in paragraphs (c)(4)(i) through (c)(5) of this section. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test to establish your operating limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test at least annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(4) If the average of your three Method 5 or 5I compliance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or 5I compliance test with the procedures in (c)(4)(i)(A) through (D) of this section.

(i) Determine your PM CPMS instrument zero output with one of the following procedures.

(A) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(B) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(C) The zero point can also can be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(D) If none of the steps in paragraphs (c)(4)(i)(A) through (C) of this section are possible, you must use a zero output value provided by the manufacturer.

(ii) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 1.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1 \,, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 1)}$$

Where:

X1 = The PM CPMS data points for the three runs constituting the performance test,

Y1 = The PM concentration value for the three runs constituting the performance test, and

n = The number of data points.

(iii) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three PM performance test runs, determine a relationship of lb/ton-clinker per milliamp with equation 2.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 2)}$$

Where:

R = The relative lb/ton clinker per milliamp for your PM CPMS.

Y1 = The three run average PM lb/ton clinker.

X1 = The three run average milliamp output from you PM CPMS.

z = the milliamp equivalent of your instrument zero determined from (c)(4)(i) of this section.

(iv) Determine your source specific 30-day rolling average operating limit using the lb/ton-clinker per milliamp value from Equation 2 above in Equation 3, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + (0.75(L)) / R \qquad \text{(Eq. 3)}$$

Where:

O_l = The operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = Your source emission limit expressed in lb/ton clinker.

z = Your instrument zero in milliamps, determined from (1)(i).

R = The relative lb/ton-clinker per milliamp for your PM CPMS, from Equation 2.

(5) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using Equation 4.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 4)}$$

Where:

X1 = The PM CPMS data points for all runs i.

n = The number of data points.

O_h = Your site specific operating limit, in milliamps.

(6) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating, and use all the PM CPMS data for calculations when the source is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 5 to determine the 30 kiln operating day average.

$$\text{30kiln operating day average} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{(Eq. 5)}$$

Where:

Hpvi = The hourly parameter value for hour i.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

(7) Use EPA Method 5 or Method 5I of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct at least three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume of 2 dscm for determining compliance with a new source limit and 1 dscm for determining compliance with an existing source limit. Calculate the average of the results from three consecutive runs to determine compliance. You need not determine the particulate matter collected in the impingers (''back half'') of the Method 5 or Method 5I particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

(8) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(d) You must install, operate, calibrate, and maintain a CEMS continuously monitoring and recording the concentration by volume of NO_X emissions into the atmosphere for any kiln subject to the NO_X emissions limit in § 60.62(a)(3). If the kiln has an alkali bypass, NO_X emissions from the alkali bypass do not need to be monitored, and NO_X emission monitoring of the kiln exhaust may be done upstream of any commingled alkali bypass gases.

(e) You must install, operate, calibrate, and maintain a CEMS for continuously monitoring and recording the concentration by volume of SO_2 emissions into the atmosphere for any kiln subject to the SO_2 emissions limit in § 60.62(a)(4). If you are complying with the alternative 90 percent SO_2 emissions reduction emissions limit, you must also continuously monitor and record the concentration by volume of SO_2 present at the wet scrubber inlet.

(f) The NO_X and SO_2 CEMS required under paragraphs (d) and (e) of this section must be installed, operated and maintained according to Performance Specification 2 of appendix B of this part and the requirements in paragraphs (f)(1) through (5) of this section.

(1) The span value of each NO_X CEMS monitor must be set at 125 percent of the maximum estimated hourly potential NO_X emission concentration that translates to the applicable emissions limit at full clinker production capacity.

(2) You must conduct performance evaluations of each NO_X CEMS monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to this part. You must use Methods 7, 7A, 7C, 7D, or 7E of appendix A–4 to this part for conducting the relative accuracy evaluations. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to Method 7 or 7C of appendix A–4 to this part.

(3) The span value for the SO_2 CEMS monitor is the SO_2 emission concentration that corresponds to 125 percent of the applicable emissions limit at full clinker production capacity

and the expected maximum fuel sulfur content.

(4) You must conduct performance evaluations of each SO_2 CEMS monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to this part. You must use Methods 6, 6A, or 6C of appendix A–4 to this part for conducting the relative accuracy evaluations. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to Method 6 or 6A of appendix A–4 to this part.

(5) You must comply with the quality assurance requirements in Procedure 1 of appendix F to this part for each NO_X and SO_2 CEMS, including quarterly accuracy determinations for monitors, and daily calibration drift tests.

(g) For each CPMS or CEMS required under paragraphs (c) through (e) of this section:

* * * * *

(2) You may not use data recorded during the monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. An owner or operator must use all the data collected during all other periods in reporting emissions or operating levels.

* * * * *

(h) You must install, operate, calibrate, and maintain instruments for continuously measuring and recording the stack gas flow rate to allow determination of the pollutant mass emissions rate to the atmosphere for each kiln subject to the PM emissions limits in § 60.62(a)(1)(ii) and (iii) and (b)(1)(i) and (ii), the NO_X emissions limit in § 60.62(a)(3), or the SO_2 emissions limit in § 60.62(a)(4) according to the requirements in paragraphs (h)(1) through (10), where appropriate, of this section.

(1) The owner or operator must install each sensor of the flow rate monitoring system in a location that provides representative measurement of the exhaust gas flow rate at the sampling location of the NO_X and/or SO_2 CEMS, taking into account the manufacturer's recommendations. The flow rate sensor is that portion of the system that senses the volumetric flow rate and generates an output proportional to that flow rate.

* * * * *

(6) The flow rate monitoring system must be designed to measure a minimum of one cycle of operational flow for each successive 15-minute period.

(7) The flow rate sensor must be able to determine the daily zero and upscale calibration drift (CD) (see sections 3.1 and 8.3 of Performance Specification 2 in appendix B to this part for a discussion of CD).

* * * * *

(8) You must perform an initial relative accuracy test of the flow rate monitoring system according to section 8.2 of Performance Specification 6 of appendix B to this part, with the exceptions noted in paragraphs (h)(8)(i) and (ii) of this section.

* * * * *

(9) You must verify the accuracy of the flow rate monitoring system at least once per year by repeating the relative accuracy test specified in paragraph (h)(8) of this section.

* * * * *

(i) *Development and Submittal (Upon Request) of Monitoring Plans.* To demonstrate compliance with any applicable emissions limit through performance stack testing or other emissions monitoring (including PM CPMS), you must develop a site-specific monitoring plan according to the requirements in paragraphs (i)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 60.13(3)(i). If you use a bag leak detector system (BLDS), you must also meet the requirements specified in paragraph § 63.1350(m)(10) of this chapter.

(1) For each continuous monitoring system (CMS) required in this section, you must develop, and submit to the permitting authority for approval upon request, a site-specific monitoring plan that addresses paragraphs (i)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 30 days before the initial performance evaluation of your CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

* * * * *

■ 5. Section 60.64 is revised to read as follows:

§ 60.64 Test methods and procedures.

(a) In conducting the performance tests and relative accuracy tests required in § 60.8, you must use reference methods and procedures and the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b)(1)You must demonstrate compliance with the PM standards in § 60.62 using EPA method 5 or method 5I.

(2) Use Method 9 and the procedures in § 60.11 to determine opacity.

(3) Any sources other than kilns (including associated alkali bypass and clinker cooler) that are subject to the 10 percent opacity limit must follow the appropriate monitoring procedures in § 63.1350(f), (m)(1)through (4), (10) and (11), (o), and (p) of this chapter.

(c) Calculate and record the rolling 30 kiln operating day average emission rate daily of NO_X and SO_2 according to the procedures in paragraphs (c)(1) and (2) of this section.

(1) Calculate the rolling 30 kiln operating day average emissions according to equation 6:

$$E_{30D} = k \frac{\sum_{i=1}^{n} C_i Q_i}{P} \qquad \text{(Eq. 6)}$$

Where:

E_{30D} = 30 kiln operating day average emission rate of NO_X or SO_2, lb/ton of clinker.

C_i = Concentration of NO_X or SO_2 for hour i, ppm.

Q_i = Volumetric flow rate of effluent gas for hour i, where

C_i and Q_i are on the same basis (either wet or dry), scf/hr.

P = 30 days of clinker production during the same time period as the NO_X or SO_2 emissions measured, tons.

k = Conversion factor, 1.194×10^{7} for NO_X and 1.660×10^{7} for SO_2, lb/scf/ppm.

n = Number of kiln operating hours over 30 kiln operating days.

(2) For each kiln operating hour for which you do not have at least one valid 15-minute CEMS data value, use the average emissions rate (lb/hr) from the most recent previous hour for which valid data are available.

(d)(1) Within 60 days after the date of completing each performance test (see § 60.8) as required by this subpart you must submit the results of the performance tests conducted to demonstrate compliance under this subpart to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk, flash drive or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the CBI, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation test as defined in § 63.2, you must submit relative accuracy test audit (RATA) data to the EPA's CDX by using CEDRI in accordance with paragraph (d)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in § 63.13.

(3) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(4) All reports required by this subpart not subject to the requirements in paragraphs (d)(1) and (2) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (d)(1) and (2) of this section in paper format.

■ 6. Section 60.65 is revised to read as follows:

§ 60.65 Recordkeeping and reporting requirements.

(a) Each owner or operator required to install a CPMS or CEMS under sections § 60.63(c) through (e) shall submit reports of excess emissions. The content of these reports must comply with the requirements in § 60.7(c). Notwithstanding the provisions of § 60.7(c), such reports shall be submitted semiannually.

(b) Each owner or operator of facilities subject to the provisions of § 60.63(c) through (e) shall submit semiannual reports of the malfunction information required to be recorded by § 60.7(b). These reports shall include the frequency, duration, and cause of any incident resulting in deenergization of any device controlling kiln emissions or in the venting of emissions directly to the atmosphere.

(c) The requirements of this section remain in force until and unless the Agency, in delegating enforcement authority to a State under section 111(c) of the Clean Air Act, 42 U.S.C. 7411, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In that event, affected sources within the State will be relieved of the obligation to comply with this section, provided that they comply with the requirements established by the State.

■ 7. Section 60.66 is amended by revising paragraph (b) introductory text to read as follows:

§ 60.66 Delegation of authority.

* * * * *

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

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

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

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

Subpart LLL—[Amended]

■ 9. Section 63.1340 is amended by revising paragraphs (b)(1), (b)(6) through (9), and (c) to read as follows:

§ 63.1340 What parts of my plant does this subpart cover?

* * * * *

(b) * * *:

(1) Each kiln including alkali bypasses and inline coal mills, except for kilns that burn hazardous waste and are subject to and regulated under subpart EEE of this part;

* * * * *

(6) Each raw material, clinker, or finished product storage bin at any portland cement plant that is a major source;

(7) Each conveying system transfer point including those associated with coal preparation used to convey coal from the mill to the kiln at any portland cement plant that is a major source;

(8) Each bagging and bulk loading and unloading system at any portland cement plant that is a major source; and

(9) Each open clinker storage pile at any portland cement plant.

(c) Onsite sources that are subject to standards for nonmetallic mineral processing plants in subpart OOO, part 60 of this chapter are not subject to this subpart. Crushers are not covered by this subpart regardless of their location.

* * * * *

■ 10. Section 63.1341 is amended by:

■ a. Removing definitions of ''Enclosed storage pile,'' and ''Inactive clinker pile'';

■ b. Adding a definition for ''In-line coal mill,'' ''Open clinker storage pile,'' ''Startup,'' and ''Shutdown'' in alphabetical order; and

■ c. Revising definitions for ''Kiln,'' ''New source,'' ''Operating day,'' ''Raw material dryer,'' and ''Total organic HAP,''.

The additions and revisions read as follows:

§ 63.1341 Definitions.

* * * * *

In-line coal mill means those coal mills using kiln exhaust gases in their process. Coal mills with a heat source other than the kiln or coal mills using exhaust gases from the clinker cooler are not an in-line coal mill.

* * * * *

Kiln means a device, including any associated preheater or precalciner devices, inline raw mills, inline coal mills or alkali bypasses that produces clinker by heating limestone and other materials for subsequent production of portland cement. Because the inline raw mill and inline coal mill are considered an integral part of the kiln, for purposes of determining the appropriate emissions limit, the term kiln also applies to the exhaust of the inline raw mill and the inline coal mill.

* * * * *

New source means any source that commenced construction or reconstruction after May 6, 2009, for purposes of determining the applicability of the kiln, clinker cooler and raw material dryer emissions limits for mercury, PM, THC, and HCl.

* * * * *

Open clinker storage pile means a clinker storage pile on the ground for more than three days that is not completely enclosed in a building or structure.

Operating day means any 24-hour period beginning at 12:00 midnight during which the kiln operates for any time. For calculating the rolling 30-day average emissions, kiln operating days do not include the hours of operation during startup or shutdown.

* * * * *

Raw material dryer means an impact dryer, drum dryer, paddle-equipped rapid dryer, air separator, or other equipment used to reduce the moisture content of feed or other materials.

* * * * *

Shutdown means the cessation of kiln operation. Shutdown begins when feed to the kiln is halted and ends when continuous kiln rotation ceases.

* * * * *

Startup means the time from when a shutdown kiln first begins firing fuel until it begins producing clinker. Startup begins when a shutdown kiln turns on the induced draft fan and begins firing fuel in the main burner. Startup ends when feed is being continuously introduced into the kiln for at least 120 minutes or when the feed rate exceeds 60 percent of the kiln design limitation rate, whichever occurs first.

* * * * *

Total organic HAP means, for the purposes of this subpart, the sum of the concentrations of compounds of formaldehyde, benzene, toluene, styrene, m-xylene, p-xylene, o-xylene, acetaldehyde, and naphthalene as measured by EPA Test Method 320 or Method 18 of appendix A to this part or ASTM D6348–03 [1] or a combination of these methods, as appropriate. If measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating the total organic HAP value. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 18 fractions) may include a combination of method detection level data and analytical data reported above the method detection level. The owner or operator of an affected source may request the use of other test methods to make this determination under paragraphs 63.7(e)(2)(ii) and (f) of this part.

* * * * *

■ 11. Section 63.1343 is revised to read as follows:

§ 63.1343 What standards apply to my kilns, clinker coolers, raw material dryers, and open clinker storage piles?

(a) *General.* The provisions in this section apply to each kiln and any alkali bypass associated with that kiln, clinker cooler, raw material dryer, and open clinker storage pile. All D/F, HCl, and total hydrocarbon (THC) emissions limit are on a dry basis. The D/F, HCl, and THC limits for kilns are corrected to 7 percent oxygen. All THC emissions limits are measured as propane. Standards for mercury and THC are based on a rolling 30-day average. If using a CEMS to determine compliance with the HCl standard, this standard is based on a rolling 30-day average. You must ensure appropriate corrections for moisture are made when measuring flow rates used to calculate mercury emissions. The 30-day period means 30 consecutive kiln operating days excluding periods of startup and shutdown. All emissions limits for kilns, clinker coolers, and raw material dryers currently in effect that are superseded by the limits below continue to apply until the compliance date of the limits below, or until the source certifies compliance with the limits below, whichever is earlier.

(b) *Kilns, clinker coolers, raw material dryers, raw mills, and finish mills.* (1) The emissions limits for these sources are shown in Table 1 below. PM limits for existing kilns also apply to kilns that have undergone a modification as defined in subpart A of part 60 of title 40.

[1] When using ASTM D6348–03, the following conditions must be met:

(1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; (2) For ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348–03 test data to be acceptable for a target analyte percent R must be 70 percent ≥ R ≤ 130 percent; and (4) The percent R value for each compound must be reported in the test report and all field measurements corrected with the calculated percent R value for that compound using the following equation: Reported Result = The measured concentration in the stack divided by the calculated percent R value and then the whole term multiplied by 100.

TABLE 1—EMISSIONS LIMITS FOR KILNS, CLINKER COOLERS, RAW MATERIAL DRYERS, RAW AND FINISH MILLS

	If your source is a (an):	And the operating mode is:	And if is located at a:	Your emissions limits are:	And the units of the emissions limit are:	The oxygen correction factor is:
1.	Existing kiln	Normal operation	Major or area source	PM [1] 0.07	lb/ton clinker	NA.
				D/F [2] 0.2	ng/dscm (TEQ)	7 percent.
				Mercury 55	lb/MM tons clinker	NA.
				THC [3 4] 24	ppmvd	7 percent.
2.	Existing kiln	Normal operation	Major source	HCl 3	ppmvd	7 percent.
3.	Existing kiln	Startup and shutdown.	Major or area source	Work practices (63.1346(f))	NA	NA.
4.	New kiln	Normal operation	Major or area source	PM 0.02	lb/ton clinker	NA.
				D/F [2] 0.2	ng/dscm (TEQ)	7 percent.
				Mercury 21	lb/MM tons clinker	NA
				THC [3 4] 24	ppmvd	7 percent.
5.	New kiln	Normal operation	Major source	HCl 3	ppmvd	7 percent.
6.	New kiln	Startup and shutdown.	Major or area source	Work practices (63.1346(f))	NA	NA.
7.	Existing clinker cooler.	Normal operation	Major or area source	PM 0.07	lb/ton clinker	NA.
8.	Existing clinker cooler.	Startup and shutdown.	Major or area source	Work practices (63.1348(b)(9))	NA	NA.
9.	New clinker cooler	Normal operation	Major or area source	PM 0.02	lb/ton clinker	NA.
10.	New clinker cooler	Startup and shutdown.	Major or area source	Work practices (63.1348(b)(9))	NA	NA.
11.	Existing or new raw material dryer.	Normal operation	Major or area source	THC [3 4] 24	ppmvd	NA.
12.	Existing or new raw material dryer.	Startup and shutdown.	Major or area source	Work practices (63.1348(b)(9))	NA	NA.
13.	Existing or new raw or finish mill.	All operating modes	Major source	Opacity 10	percent	NA.

[1] The initial and subsequent PM performance tests are performed using Method 5 or 5I and consist of three 1-hr tests.
[2] If the average temperature at the inlet to the first PM control device (fabric filter or electrostatic precipitator) during the D/F performance test is 400 °F or less this limit is changed to 0.40 ng/dscm (TEQ).
[3] Measured as propane.
[4] Any source subject to the 24 ppmvd THC limit may elect to meet an alternative limit of 12 ppmvd for total organic HAP.

(2) When there is an alkali bypass and/or an inline coal mill with a separate stack associated with a kiln, the combined PM emissions from the kiln and the alkali bypass stack and/or the inline coal mill stack are subject to the PM emissions limit. Existing kilns that combine the clinker cooler exhaust and/or coal mill exhaust with the kiln exhaust and send the combined exhaust to the PM control device as a single stream may meet an alternative PM emissions limit. This limit is calculated using Equation 1 of this section:

$$PM_{alt} = (0.0060 \times 1.65)(Q_k + Q_c + Q_{ab} + Q_{cm})/(7000) \quad \text{(Eq. 1)}$$

Where:

PM_{alt} = Alternative PM emission limit for commingled sources.

0.006 = The PM exhaust concentration (gr/dscf) equivalent to 0.070 lb per ton clinker where clinker cooler and kiln exhaust gas are not combined.

1.65 = The conversion factor of ton feed per ton clinker.

Q_k = The exhaust flow of the kiln (dscf/ton feed).

Q_c = The exhaust flow of the clinker cooler (dscf/ton feed).

Q_{ab} = The exhaust flow of the alkali bypass (dscf/ton feed).

Q_{cm} = The exhaust flow of the coal mill (dscf/ton feed).

7000 = The conversion factor for grains (gr) per lb.

For new kilns that combine kiln exhaust and clinker cooler gas the limit is calculated using the Equation 2 of this section:

$$PM_{alt} = (0.0020 \times 1.65)(Q_k + Q_c + Q_{ab} + Q_{cm})/(7000) \quad \text{(Eq. 2)}$$

Where:

PM_{alt} = Alternative PM emission limit for commingled sources.

0.002 = The PM exhaust concentration (gr/dscf) equivalent to 0.020 lb per ton clinker where clinker cooler and kiln exhaust gas are not combined.

1.65 = The conversion factor of ton feed per ton clinker.

Q_k = The exhaust flow of the kiln (dscf/ton feed).

Q_c = The exhaust flow of the clinker cooler (dscf/ton feed).

Q_{ab} = The exhaust flow of the alkali bypass (dscf/ton feed).

Q_{cm} = The exhaust flow of the coal mill (dscf/ton feed).

7000 = The conversion factor for gr per lb.

(c) *Open clinker storage pile.* The owner or operator of an open clinker storage pile must prepare, and operate in accordance with, the fugitive dust emissions control measures, described in their operation and maintenance plan (see § 63.1347 of this subpart), that is appropriate for the site conditions as specified in paragraphs (c)(1) through

(3) of this section. The operation and maintenance plan must also describe the measures that will be used to minimize fugitive dust emissions from piles of clinker, such as accidental spillage, that are not part of open clinker storage piles.

(1) The operation and maintenance plan must identify and describe the location of each current or future open clinker storage pile and the fugitive dust emissions control measures the owner or operator will use to minimize fugitive dust emissions from each open clinker storage pile.

(2) For open clinker storage piles, the operations and maintenance plan must specify that one or more of the following control measures will be used to minimize to the greatest extent practicable fugitive dust from open clinker storage piles: Locating the source inside a partial enclosure, installing and operating a water spray or fogging system, applying appropriate chemical dust suppression agents, use of a wind barrier, compaction, use of tarpaulin or other equally effective cover or use of a vegetative cover. You must select, for inclusion in the operations and maintenance plan, the fugitive dust control measure or measures listed in this paragraph that are most appropriate for site conditions. The plan must also explain how the measure or measures selected are applicable and appropriate for site conditions. In addition, the plan must be revised as needed to reflect any changing conditions at the source.

(3) Temporary piles of clinker that result from accidental spillage or clinker storage cleaning operations must be cleaned up within 3 days.

(d) Emission limits in effect prior to September 9, 2010. Any source defined as an existing source in § 63.1351, and that was subject to a PM, mercury, THC, D/F, or opacity emissions limit prior to September 9, 2010, must continue to meet the limits shown in Table 2 to this section until September 9, 2015.

■ 12. Section 63.1344 is revised to read as follows:

§ 63.1344 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.1343(b) and (c) and § 63.1345 and you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

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

(1) The violation:

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

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

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

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

(2) Repairs were made as expeditiously as possible when a violation occurred; and

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

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

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

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

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

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

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

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

■ 13. Section 63.1345 is revised to read as follows:

§ 63.1345 Emissions limits for affected sources other than kilns; clinker coolers; new and reconstructed raw material dryers.

The owner or operator of each new or existing raw material, clinker, or finished product storage bin; conveying system transfer point; bagging system; bulk loading or unloading system; raw and finish mills; and each existing raw material dryer, at a facility which is a major source subject to the provisions of this subpart must not cause to be discharged any gases from these affected sources which exhibit opacity in excess of 10 percent.

■ 14. Section 63.1346 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising paragraph (a)(1);

■ c. Revising paragraphs (c) through (f); and

■ d. Adding paragraph (g)

The revisions read as follows:

§ 63.1346 Operating limits for kilns.

(a) The owner or operator of a kiln subject to a D/F emissions limitation under § 63.1343 must operate the kiln such that the temperature of the gas at the inlet to the kiln PM control device (PMCD) and alkali bypass PMCD, if applicable, does not exceed the applicable temperature limit specified in paragraph (b) of this section. The owner or operator of an in-line kiln/raw mill subject to a D/F emissions limitation under § 63.1343 must operate the in-line kiln/raw mill, such that:

(1) When the raw mill of the in-line kiln/raw mill is operating, the applicable temperature limit for the main in-line kiln/raw mill exhaust, specified in paragraph (b) of this section and established during the performance test when the raw mill was operating, is not exceeded, except during periods of startup and shutdown when the

temperature limit may be exceeded by no more than 10 percent.

* * * * *

(c) For an affected source subject to a D/F emissions limitation under § 63.1343 that employs sorbent injection as an emission control technique for D/F control, you must operate the sorbent injection system in accordance with paragraphs (c)(1) and (2) of this section.

(1) The rolling three-hour average activated sorbent injection rate must be equal to or greater than the sorbent injection rate determined in accordance with § 63.1349(b)(3)(vi).

(2) You must either:

(i) Maintain the minimum activated carbon injection carrier gas flow rate, as a rolling three-hour average, based on the manufacturer's specifications. These specifications must be documented in the test plan developed in accordance with § 63.7(c), or

(ii) Maintain the minimum activated carbon injection carrier gas pressure drop, as a rolling three-hour average, based on the manufacturer's specifications. These specifications must be documented in the test plan developed in accordance with § 63.7(c).

(d) Except as provided in paragraph (e) of this section, for an affected source subject to a D/F emissions limitation under § 63.1343 that employs carbon injection as an emission control technique you must specify and use the brand and type of sorbent used during the performance test until a subsequent performance test is conducted, unless the site-specific performance test plan contains documentation of key parameters that affect adsorption and the owner or operator establishes limits based on those parameters, and the limits on these parameters are maintained.

(e) For an affected source subject to a D/F emissions limitation under § 63.1343 that employs carbon injection as an emission control technique you may substitute, at any time, a different brand or type of sorbent provided that the replacement has equivalent or improved properties compared to the sorbent specified in the site-specific performance test plan and used in the performance test. The owner or operator must maintain documentation that the substitute sorbent will provide the same or better level of control as the original sorbent.

(f) No kiln may use as a raw material or fuel any fly ash where the mercury content of the fly ash has been increased through the use of activated carbon, or any other sorbent, unless the facility can demonstrate that the use of that fly ash will not result in an increase in mercury emissions over baseline emissions (i.e., emissions not using the fly ash). The facility has the burden of proving there has been no emissions increase over baseline. Once the kiln is in compliance with a mercury emissions limit specified in § 63.1343, this paragraph no longer applies.

(g) During periods of startup and shutdown you must meet the requirements listed in (g)(1) through (4) of this section.

(1) During startup you must use any one or combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, synthesis gas (syngas), and ultra-low sulfur diesel (ULSD) until the kiln reaches a temperature of 1200 degrees Fahrenheit.

(2) Combustion of the primary kiln fuel may commence once the kiln temperature reaches 1200 degrees Fahrenheit.

(3) All air pollution control devices must be turned on and operating prior to combusting any fuel.

(4) You must keep records as specified in § 63.1355 during periods of startup and shutdown.

■ 15. Section 63.1347 is amended by revising paragraph (a)(1) to read as follows:

§ 63.1347 Operation and maintenance plan requirements.

(a) * * *

(1) Procedures for proper operation and maintenance of the affected source and air pollution control devices in order to meet the emissions limits and operating limits, including fugitive dust control measures for open clinker piles, of §§ 63.1343 through 63.1348. Your operations and maintenance plan must address periods of startup and shutdown;

* * * * *

■ 16. Section 63.1348 is amended by:

■ a. Revising paragraphs (a) introductory text and (a)(1) and (2);

■ b. Adding two sentences to paragraph (a)(3)(i);

■ c. Revising paragraph (a)(3)(ii);

■ d. Revising paragraphs (a)(3)(iii) and (iv);

■ e. Revising paragraphs (a)(4) through (8);

■ f. Revising paragraph (b); and

■ g. Revising paragraph (c)(2)(iv).

The revisions and additions read as follows:

§ 63.1348 Compliance requirements.

(a) *Initial Performance Test Requirements.* For an affected source subject to this subpart, you must demonstrate compliance with the emissions standards and operating limits by using the test methods and procedures in §§ 63.1349 and 63.7. Any cement kiln that has been subject to the requirements of subpart CCCC or subpart DDDD of 40 CFR Part 60, and is now electing to cease burning nonhazardous solid waste and become subject to this subpart, must meet all the initial compliance testing requirements each time it becomes subject to this subpart, even if it was previously subject to this subpart.

NOTE to paragraph (a): The first day of the 30 operating day performance test is the first day after the compliance date following completion of the field testing and data collection that demonstrates that the CPMS or CEMS has satisfied the relevant CPMS performance evaluation or CEMS performance specification (e.g., PS 2, 12A, or 12B) acceptance criteria. The performance test period is complete at the end of the 30th consecutive operating day. See § 63.1341 for definition of operating day and § 63.1348(b)(1) for the CEMS operating requirements. The source has the option of performing the compliance test earlier then the compliance date if desired.

(1) *PM Compliance.* If you are subject to limitations on PM emissions under § 63.1343(b), you must demonstrate compliance with the PM emissions standards by using the test methods and procedures in § 63.1349(b)(1).

(2) *Opacity Compliance.* If you are subject to the limitations on opacity under § 63.1345, you must demonstrate compliance with the opacity emissions standards by using the performance test methods and procedures in § 63.1349(b)(2). Use the maximum 6-minute average opacity exhibited during the performance test period to determine whether the affected source is in compliance with the standard.

(3) * * *

(i) * * * The owner or operator of a kiln with an in-line raw mill must demonstrate compliance by conducting separate performance tests while the raw mill is operating and while the raw mill is not operating. Determine the D/F TEQ concentration for each run and calculate the arithmetic average of the TEQ concentrations measured for the three runs to determine continuous compliance.

(ii) If you are subject to a D/F emissions limitation under § 63.1343(b), you must demonstrate compliance with the temperature operating limits specified in § 63.1346 by using the performance test methods and procedures in § 63.1349(b)(3)(ii) through (b)(3)(iv). Use the arithmetic average of the temperatures measured during the

three runs to determine the applicable temperature limit.

(iii) If activated carbon injection is used and you are subject to a D/F emissions limitation under § 63.1343(b), you must demonstrate compliance with the activated carbon injection rate operating limits specified in § 63.1346 by using the performance test methods and procedures in § 63.1349(b)(3)(v).

(iv) If activated carbon injection is used, you must also develop a carrier gas parameter (either the carrier gas flow rate or the carrier gas pressure drop) during the initial performance test and updated during any subsequent performance test conducted under § 63.1349(b)(3) that meets the requirements of § 63.1349(b)(3)(vi). Compliance is demonstrated if the system is maintained within +/- 5 percent accuracy during the performance test determined in accordance with the procedures and criteria submitted for review in your monitoring plan required in section 63.1350(p).

(4)(i) *THC Compliance.* If you are subject to limitations on THC emissions under § 63.1343(b), you must demonstrate compliance with the THC emissions standards by using the performance test methods and procedures in § 63.1349(b)(4)(i). You must use the average THC concentration obtained during the first 30 kiln operating days after the compliance date of this rule to determine initial compliance.

(ii) *Total Organic HAP Emissions Tests.* If you elect to demonstrate compliance with the total organic HAP emissions limit under § 63.1343(b) in lieu of the THC emissions limit, you must demonstrate compliance with the total organic HAP emissions standards by using the performance test methods and procedures in § 63.1349(b)(7.

(iii) If you are demonstrating initial compliance, you must conduct the separate performance tests as specified in § 63.1349(b)(7) while the raw mill of the inline kiln/raw mill is operating and while the raw mill of the inline kiln/raw mill is not operating.

(iv) The average total organic HAP concentration measured during the separate initial performance test specified by § 63.1349(b)(7) must be used to determine initial compliance.

(v) The average THC concentration measured during the initial performance test specified by § 63.1349(b)(4) must be used to determine the site-specific THC limit. Using the fraction of time the inline kiln/raw mill is on and the fraction of time that the inline kiln/raw mill is off, calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off testing using one of the two approaches in § 63.1349(b)(7)(vii) or (viii) depending on the level of organic HAP measured during the compliance test.

(5) *Mercury Compliance.* If you are subject to limitations on mercury emissions in § 63.1343(b), you must demonstrate compliance with the mercury standards by using the performance test methods and procedures in § 63.1349(b)(5). You must demonstrate compliance by operating a mercury CEMS or a sorbent trap based CEMS. Compliance with the mercury emissions standard must be determined based on the first 30 operating days you operate a mercury CEMS or sorbent trap monitoring system after the compliance date of this rule.

(i) In calculating a 30 operating day emissions value using an integrating sorbent trap CEMS, assign the average Hg emissions concentration determined for an integrating period (e.g., 7 day sorbent trap monitoring system sample) to each relevant hour of the kiln operating days spanned by each integrated sample. Calculate the 30 kiln operating day emissions rate value using the assigned hourly Hg emissions concentrations and the respective flow and production rate values collected during the 30 kiln operating day performance test period. Depending on the duration of each integrated sampling period, you may not be able to calculate the 30 kiln operating day emissions value until several days after the end of the 30 kiln operating day performance test period.

(ii) For example, a sorbent trap monitoring system producing an integrated 7-day sample will provide Hg concentration data for each hour of the first 28 kiln operating days (i.e., four values spanning 7 days each) of a 30 operating day period. The Hg concentration values for the hours of the last 2 days of the 30 operating day period will not be available for calculating the emissions for the performance test period until at least five days after the end of the subject period.

(6) *HCl Compliance.* If you are subject to limitations on HCl emissions under § 63.1343(b), you must demonstrate initial compliance with the HCl standards by using the performance test methods and procedures in § 63.1349(b)(6).

(i) For an affected source that is equipped with a wet scrubber, tray tower or dry scrubber, you may demonstrate initial compliance by conducting a performance test as specified in § 63.1349(b)(6)(i). You must determine the HCl concentration for each run and calculate the arithmetic average of the concentrations measured for the three runs to determine compliance. You must also establish appropriate site-specific operational parameter limits.

(ii) For an affected source that is not equipped with a wet scrubber, tray tower or dry scrubber, you must demonstrate initial compliance by operating a CEMS as specified in § 63.1349(b)(6)(ii). You must use the average of the hourly HCl values obtained during the first 30 kiln operating days that occur after the compliance date of this rule to determine initial compliance.

(7) *Commingled Exhaust Requirements.* If the coal mill exhaust is commingled with kiln exhaust in a single stack, you may demonstrate compliance with the kiln emission limits by either:

(i) Performing required emissions monitoring and testing on the commingled coal mill and kiln exhaust, or

(ii) Perform required emission monitoring and testing of the kiln exhaust prior to the reintroduction of the coal mill exhaust, and also testing the kiln exhaust diverted to the coal mill. All emissions must be added together for all emission points, and must not exceed the limit per each pollutant as listed in S63.1343(b).

(b) *Continuous Monitoring Requirements.* You must demonstrate compliance with the emissions standards and operating limits by using the performance test methods and procedures in §§ 63.1350 and 63.8 for each affected source.

(1) *General Requirements.* (i) You must monitor and collect data according to § 63.1350 and the site-specific monitoring plan required by § 63.1350(p).

(ii) Except for periods of startup and shutdown, monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), you must operate the monitoring system and collect data at all required intervals at all times the affected source is operating.

(iii) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. A monitoring system malfunction is any

sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(iv) *Clinker Production.* If you are subject to limitations on mercury emissions (lb/MM tons of clinker) under § 63.1343(b), you must determine the hourly production rate of clinker according to the requirements of § 63.1350(d).

(2) *PM Compliance.* If you are subject to limitations on PM emissions under § 63.1343(b), you must use the monitoring methods and procedures in § 63.1350(b) and (d).

(3) *Opacity Compliance.* If you are subject to the limitations on opacity under § 63.1345, you must demonstrate compliance using the monitoring methods and procedures in § 63.1350(f) based on the maximum 6-minute average opacity exhibited during the performance test period. You must initiate corrective actions within one hour of detecting visible emissions above the applicable limit.

(i) *COMS.* If you install a COMS in lieu of conducting the daily visible emissions testing, you must demonstrate compliance using a COMS such that it is installed, operated, and maintained in accordance with the requirements of § 63.1350(f)(4)(i).

(ii) Bag leak determination system (*BLDS).* If you install a BLDS on a raw mill or finish mill in lieu of conducting the daily visible emissions testing, you must demonstrate compliance using a BLDS that is installed, operated, and maintained in accordance with the requirements of § 63.1350(f)(4)(ii).

(4) *D/F Compliance.* If you are subject to a D/F emissions limitation under § 63.1343(b), you must demonstrate compliance using a CMS that is installed, operated and maintained to record the temperature of specified gas streams in accordance with the requirements of § 63.1350(g).

(5)(i) *Activated Carbon Injection Compliance.* If you use activated carbon injection to comply with the D/F emissions limitation under § 63.1343(b), you must demonstrate compliance using a CMS that is installed, operated, and maintained to record the rate of activated carbon injection in accordance with the requirements § 63.1350(h)(1).

(ii) If you use activated carbon injection to comply with the D/F emissions limitation under § 63.1343(b), you must demonstrate compliance using a CMS that is installed, operated and maintained to record the activated carbon injection system gas parameter in accordance with the requirements of § 63.1350(h)(2).

(6) THC Compliance. (i) If you are subject to limitations on THC emissions under § 63.1343(b), you must demonstrate compliance using the monitoring methods and procedures in § 63.1350(i) and (j).

(ii) THC must be measured either upstream of the coal mill or in the coal mill stack.

(7) Mercury Compliance. (i) If you are subject to limitations on mercury emissions in § 63.1343(b), you must demonstrate compliance using the monitoring methods and procedures in § 63.1350(k). If you use an integrated sorbent trap monitoring system to determine ongoing compliance, use the procedures described in § 63.1348(a)(5) to assign hourly mercury concentration values and to calculate rolling 30 operating day emissions rates. Since you assign the mercury concentration measured with the sorbent trap to each relevant hour respectively for each operating day of the integrated period, you may schedule the sorbent trap change periods to any time of the day (i.e., the sorbent trap replacement need not be scheduled at 12:00 midnight nor must the sorbent trap replacements occur only at integral 24-hour intervals).

(ii) Mercury must be measured either upstream of the coal mill or in the coal mill stack.

(8) *HCl Compliance.* If you are subject to limitations on HCl emissions under § 63.1343(b), you must demonstrate compliance using the performance test methods and procedures in § 63.1349(b)(6).

(i) For an affected source that is not equipped with a wet scrubber, tray tower or a dry sorbent injection system, you must demonstrate compliance using the monitoring methods and procedures in § 63.1350(l)(1).

(ii) For an affected source that is equipped with a wet scrubber, tray tower or a dry sorbent injection system, you may demonstrate compliance using the monitoring methods and procedures in § 63.1350(l)(2).

(iii) HCl may be measured either upstream of the coal mill or in the coal mill stack.

(iv) As an alternative to paragraph (b)(8)(ii) of this section, you may use an SO_2 CEMS to establish an SO_2 operating level during your initial and repeat HCl performance tests and monitor the SO_2 level using the procedures in § 63.1350(l)(3).

(9) Startup and Shutdown Compliance. In order to demonstrate continuous compliance during startup and shutdown, all air pollution control devices must be operating.

(c) * * *

(2) * * *

(iv) The performance test must be completed within 360 hours after the planned operational change period begins.

* * * * *

■ 17. Section 63.1349 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising paragraph (b)(1);

■ c. Revising paragraph (b)(3) introductory text;

■ d. Revising paragraphs (b)(3)(v) and (vi);

■ e. Revising paragraphs (b)(4), (5), and (6);

■ f. Adding paragraph (b)(7) and (8); and

■ g. Revising paragraphs (c), (d)(1) introductory text, (d)(1)(ii), (d)(2), and (e).

The revisions and additions read as follows:

§ 63.1349 Performance testing requirements.

(a) You must document performance test results in complete test reports that contain the information required by paragraphs (a)(1) through (10) of this section, as well as all other relevant information. As described in § 63.7(c)(2)(i), you must make available to the Administrator prior to testing, if requested, the site-specific test plan to be followed during performance testing. For purposes of determining exhaust gas flow rate to the atmosphere from an alkali bypass stack or a coal mill stack, you must either install, operate, calibrate and maintain an instrument for continuously measuring and recording the exhaust gas flow rate according to the requirements in paragraphs § 63.1350(n)(1) through (10) of this subpart or use the maximum design exhaust gas flow rate. For purposes of determining the combined emissions from kilns equipped with an alkali bypass or that exhaust kiln gases to a coal mill that exhausts through a separate stack, instead of installing a CEMS on the alkali bypass stack or coal mill stack, you may use the results of the initial and subsequent performance test to demonstrate compliance with the relevant emissions limit.

* * * * *

(b)(1) *PM emissions tests.* The owner or operator of a kiln subject to limitations on PM emissions shall demonstrate initial compliance by conducting a performance test using Method 5 or Method 5I at appendix A–3 to part 60 of this chapter. You must

also monitor continuous performance through use of a PM continuous parametric monitoring system (PM CPMS).

(i) For your PM CPMS, you will establish a site-specific operating limit. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test to establish your operating limit. You will use the PM CPMS to demonstrate continuous compliance with your operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(A) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(B) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to three times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to three times your allowable emission limit.

(C) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(ii) Determine your operating limit as specified in paragraphs (b)(1)(iii) through (iv) of this section. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test to establish your operating limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test at least annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(iii) If the average of your three Method 5 or 5I compliance test runs is below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or 5I compliance test with the procedures in (a)(1)(iii)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

(*1*) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*2*) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*3*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*4*) If none of the steps in paragraphs (a)(1)(iii)(A)(*1*) through (*3*) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 3.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1 , \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 3)}$$

Where:

X_1 = The PM CPMS data points for the three runs constituting the performance test.

Y_1 = The PM concentration value for the three runs constituting the performance test.

n = The number of data points.

(C) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run PM compliance test average, determine a relationship of lb/ton-clinker per milliamp with Equation 4.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 4)}$$

Where:

R = The relative lb/ton-clinker per milliamp for your PM CPMS.

Y_1 = The three run average lb/ton-clinker PM concentration.

X_1 = The three run average milliamp output from you PM CPMS.

z = The milliamp equivalent of your instrument zero determined from (b)(1)(iii)(A).

(D) Determine your source specific 30-day rolling average operating limit using the lb/ton-clinker per milliamp value from Equation 4 in Equation 5, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \quad \text{(Eq. 5)}$$

Where:

O_l = The operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = Your source emission limit expressed in lb/ton clinker.

z = Your instrument zero in milliamps, determined from (1)(i).

R = The relative lb/ton-clinker per milliamp for your PM CPMS, from Equation 4.

(iv) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using Equation 6.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \quad \text{(Eq. 6)}$$

Where:

X_1 = The PM CPMS data points for all runs i.

n = The number of data points.

O_h = Your site specific operating limit, in milliamps.

(v) To determine continuous operating compliance, you must record the PM CPMS output data for all periods when the process is operating, and use all the PM CPMS data for calculations when the source is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 7 to determine the 30 kiln operating day average.

$$30\text{kiln operating day} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad \text{(Eq. 7)}$$

Where:

Hpvi = The hourly parameter value for hour i.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

(vi) For each performance test, conduct at least three separate test runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume of 2 dscm for determining compliance with a new source limit and 1 dscm for determining compliance with an existing source limit. Calculate the average of the results from three consecutive runs, including applicable sources as required by (D)(viii), to determine compliance. You need not determine the particulate matter collected in the impingers (''back half'') of the Method 5 or Method 5I particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

(vii) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(viii) When there is an alkali bypass and/or an inline coal mill with a separate stack associated with a kiln, the main exhaust and alkali bypass and/or inline coal mill must be tested simultaneously and the combined emission rate of PM from the kiln and alkali bypass and/or inline coal mill must be computed for each run using Equation 8 of this section.

$$E_c = \frac{E_K + E_B + E_C}{P} \quad \text{(Eq. 8)}$$

Where:

E_C = Combined hourly emission rate of PM from the kiln and bypass stack and/or inline coal mill, lb/ton of kiln clinker production.

E_K = Hourly emissions of PM emissions from the kiln, lb.

E_B = Hourly PM emissions from the alkali bypass stack, lb.

E_C = Hourly PM emissions from the inline coal mill stack, lb.

P = Hourly clinker production, tons.

(ix) The owner or operator of a kiln with an in-line raw mill and subject to limitations on PM emissions shall demonstrate initial compliance by conducting separate performance tests while the raw mill is under normal operating conditions and while the raw mill is not operating.

* * * * *

(3) *D/F Emissions Tests.* If you are subject to limitations on D/F emissions under this subpart, you must conduct a performance test using Method 23 of appendix A–7 to part 60 of this chapter. If your kiln or in-line kiln/raw mill is equipped with an alkali bypass, you must conduct simultaneous performance tests of the kiln or in-line kiln/raw mill exhaust and the alkali bypass. You may conduct a performance test of the alkali bypass exhaust when the raw mill of the in-line kiln/raw mill is operating or not operating.

* * * * *

(v)(A) If sorbent injection is used for D/F control, you must record the rate of sorbent injection to the kiln exhaust, and where applicable, the rate of sorbent injection to the alkali bypass exhaust, continuously during the period of the Method 23 test in accordance with the conditions in § 63.1350(m)(9), and include the continuous injection rate record(s) in the performance test report. Determine the sorbent injection rate parameters in accordance with paragraphs (b)(3)(vi) of this section.

(B) Include the brand and type of sorbent used during the performance test in the performance test report.

(C) Maintain a continuous record of either the carrier gas flow rate or the carrier gas pressure drop for the duration of the performance test. If the carrier gas flow rate is used, determine, record, and maintain a record of the accuracy of the carrier gas flow rate monitoring system according to the procedures in appendix A to part 75 of this chapter. If the carrier gas pressure drop is used, determine, record, and maintain a record of the accuracy of the carrier gas pressure drop monitoring system according to the procedures in § 63.1350(m)(6).

(vi) Calculate the run average sorbent injection rate for each run and determine and include the average of the run average injection rates in the performance test report and determine the applicable injection rate limit in accordance with § 63.1346(c)(1).

(4) *THC emissions test.* (i) If you are subject to limitations on THC emissions, you must operate a CEMS in accordance with the requirements in § 63.1350(i). For the purposes of conducting the accuracy and quality assurance evaluations for CEMS, the THC span value (as propane) is 50 ppmvd and the reference method (RM) is Method 25A of appendix A to part 60 of this chapter.

(ii) Use the THC CEMS to conduct the initial compliance test for the first 30 kiln operating days of kiln operation after the compliance date of the rule. See 63.1348(a).

(iii) If kiln gases are diverted through an alkali bypass or to a coal mill and exhausted through a separate stack, you must calculate a kiln-specific THC limit using Equation 9:

$$Cks = \frac{(MACT\ Limit \times (Qab + Qcm + Qks)) - (Qab \times Cab) - (Qcm \times Ccm)}{Qks} \quad \text{((Eq. 9)}$$

Where:

Cks = Kiln stack concentration (ppmvd).
Qab = Alkali bypass flow rate (volume/hr).
Cab = Alkali bypass concentration (ppmvd).
Qcm = Coal mill flow rate (volume/hr).
Ccm = Coal mill concentration (ppmvd).
Qks = Kiln stack flow rate (volume/hr).

(iv) THC must be measured either upstream of the coal mill or the coal mill stack.

(v) Instead of conducting the performance test specified in paragraph (b)(4)of this section, you may conduct a performance test to determine emissions of total organic HAP by following the procedures in paragraphs (b)(7) of this section.

(5) *Mercury Emissions Tests.* If you are subject to limitations on mercury emissions, you must operate a mercury CEMS or a sorbent trap monitoring system in accordance with the requirements of § 63.1350(k). The initial compliance test must be based on the first 30 kiln operating days in which the affected source operates using a mercury CEMS or a sorbent trap monitoring system after the compliance date of the rule. See § 63.1348(a).

(i) If you are using a mercury CEMS or a sorbent trap monitoring system, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the exhaust gas flow rate to the atmosphere according to the requirements in § 63.1350(k)(5).

(ii) Calculate the emission rate using Equation 10 of this section:

$$E_{30D} = k\,\frac{\sum_{i=1}^{n} C_i Q_i}{P} \quad \text{(Eq. 10)}$$

Where:

E_{30D} = 30-day rolling emission rate of mercury, lb/MM tons clinker.
C_i = Concentration of mercury for operating hour i, µg/scm.
Q_i = Volumetric flow rate of effluent gas for operating hour i, where C_i and Q_i are on the same basis (either wet or dry), scm/hr.
k = Conversion factor, 1 lb/454,000,000 µg.
n = Number of kiln operating hours in a 30 kiln operating day period.
P = 30 days of clinker production during the same time period as the mercury emissions measured, million tons.

(6) *HCl emissions tests.* For a source subject to limitations on HCl emissions you must conduct performance testing by one of the following methods:

(i)(A) If the source is equipped with a wet scrubber, tray tower or dry scrubber, you must conduct performance testing using Method 321 of appendix A to this part unless you have installed a CEMS that meets the requirements § 63.1350(l)(1). For kilns with inline raw mills, testing should be conducted for the raw mill on and raw mill off conditions.

(B) You must establish site specific parameter limits by using the CPMS required in § 63.1350(l)(1). For a wet scrubber or tray tower, measure and record the pressure drop across the scrubber and/or liquid flow rate and pH in intervals of no more than 15 minutes during the HCl test. Compute and record the 24-hour average pressure drop, pH, and average scrubber water flow rate for each sampling run in which the applicable emissions limit is met. For a dry scrubber, measure and record the sorbent injection rate in intervals of no more than 15 minutes during the HCl test. Compute and record the 24-hour average sorbent injection rate and average sorbent injection rate for each sampling run in which the applicable emissions limit is met.

(ii)(A) If the source is not controlled by a wet scrubber, tray tower or dry sorbent injection system, you must operate a CEMS in accordance with the requirements of § 63.1350(l)(1). See § 63.1348(a).

(B) The initial compliance test must be based on the 30 kiln operating days that occur after the compliance date of this rule in which the affected source operates using a HCl CEMS. Hourly HCl concentration data must be obtained according to § 63.1350(l).

(iii) As an alternative to paragraph (b)(6)(i)(B) of this section, you may choose to monitor SO_2 emissions using a CEMS in accordance with the

requirements of § 63.1350(l)(3). You must establish an SO_2 operating limit equal to the highest 1 hour average recorded during the HCl stack test. This operating limit will apply only for demonstrating HCl compliance.

(iv) If kiln gases are diverted through an alkali bypass or to a coal mill and exhausted through a separate stack, you must calculate a kiln-specific HCl limit using Equation 11:

$$Cks = \frac{(MACT\ Limit \times (Qab + Qcm + Qks)) - (Qab \times Cab) - (Qcm \times Ccm)}{Qks} \quad \text{(Eq. 11)}$$

Where:

Cks = Kiln stack concentration (ppmvd).
Qab = Alkali bypass flow rate (volume/hr).
Cab = Alkali bypass concentration (ppmvd).
Qcm = Coal mill flow rate (volume/hr).
Ccm = Coal mill concentration (ppmvd).
Qks = Kiln stack flow rate (volume/hr).

(7) *Total Organic HAP Emissions Tests.* Instead of conducting the performance test specified in paragraph (a)(4) of this section, you may conduct a performance test to determine emissions of total organic HAP by following the procedures in paragraphs (a)(7)(i) through (v) of this section.

(i) Use Method 320 of appendix A to this part, Method 18 of Appendix A of part 60, ASTM D6348–03 or a combination to determine emissions of total organic HAP. Each performance test must consist of three separate runs under the conditions that exist when the affected source is operating at the representative performance conditions in accordance with § 63.7(e). Each run must be conducted for at least 1 hour.

(ii) At the same time that you are conducting the performance test for total organic HAP, you must also determine a site-specific THC emissions limit by operating a THC CEMS in accordance with the requirements of § 63.1350(j). The duration of the performance test must be at least 3 hours and the average THC concentration (as calculated from the 1-minute averages) during the 3-hour test must be calculated. You must establish your THC operating limit and determine compliance with it according to paragraphs (a)(7)(vii)through (viii)of this section. It is permissible to extend the testing time of the organic HAP performance test if you believe extended testing is required to adequately capture THC variability over time.

(iii) If your source has an in-line kiln/raw mill you must use the fraction of time the raw mill is on and the fraction of time that the raw mill is off and calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off testing.

(iv) If your organic HAP emissions are below 75 percent of the organic HAP standard and you determine your operating limit with paragraph (b)(7)(vii) of this section your THC CEMS must be calibrated and operated on a measurement scale no greater than 180 ppmvw, as carbon, or 60 ppmvw as propane.

(v) Your THC CEMS measurement scale must be capable of reading THC concentrations from zero to a level equivalent to two times your highest THC emissions average determined during your performance test, including mill on or mill off operation. **Note:** This may require the use of a dual range instrument to meet this requirement and paragraph (b)(7)(iv) of this section.

(vi) Determine your operating limit as specified in paragraphs (a)(7)(vii) and (viii) of this section. If your organic HAP performance test demonstrates your average organic HAP emission levels are below 75 percent of your emission limit (9 ppmv) you will use the average THC value recorded during the organic HAP performance test, and the average total organic HAP result of your performance test to establish your operating limit. If your organic HAP compliance test results demonstrate your average organic HAP emission levels are at or above 75 percent of your emission limit, your operating limit is established as the average THC value recorded during the organic HAP performance test. You must establish a new operating limit after each performance test. You must repeat the performance test no later than 30 months following your last performance test and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(vii) If the average organic HAP results for your three Method 18 and/or Method 320 performance test runs are below 75 percent of your organic HAP emission limit, you must calculate an operating limit by establishing a relationship of THC CEMS signal to the organic HAP concentration using the average THC CEMS value corresponding to the three organic HAP compliance test runs and the average organic HAP total concentration from the Method 18 and/or Method 320 performance test runs with the procedures in (a)(7)(vii)(A) and (B) of this section.

(A) Determine the THC CEMS average values in ppmvw, and the average of your corresponding three total organic HAP compliance test runs, using Equation 12.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_i \ , \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_i \quad \text{(Eq. 12)}$$

Where:

$\bar{x}$ = The THC CEMS average values in ppmvw.
Xi= The THC CEMS data points for all three runs i.
Yi= The sum of organic HAP concentrations for test runs i. and
n = The number of data points.

(B) You must use your three run average THC CEMS value, and your three run average organic HAP concentration from your three Method 18 and/or Method 320 compliance tests to determine the operating limit. Use equation 13 to determine your operating limit in units of ppmvw THC, as propane.

$$T_l = \left(\frac{9}{Y_1}\right) * X_1 \quad \text{(Eq. 13)}$$

Where:

T_1 = The 30-day operating limit for your THC CEMS, ppmvw.

Y_1 = The average organic HAP concentration from Eq. 12, ppmv.

X_1 = The average THC CEMS concentration from Eq. 12, ppmvw.

(viii) If the average of your three organic HAP performance test runs is at or above 75 percent of your organic HAP emission limit, you must determine your operating limit using Equation 14 by averaging the THC CEMS output values corresponding to your three organic HAP performance test runs that demonstrate compliance with the emission limit. If your new THC CEMS value is below your current operating limit, you may opt to retain your current operating limit, but you must still submit all performance test and THC CEMS data according to the reporting requirements in paragraph (d)(1) of this section.

$$T_h = \frac{1}{n}\sum_{i=1}^{n} X_1 , \qquad \text{(Eq. 14)}$$

Where:

X1 = The THC CEMS data points for all runs i.

Y1 = The organic HAP total value for runs i.

n = The number of data points.

T_h = Your site specific operating limit, in ppmvw THC.

(ix) If your kiln has an inline kiln/raw mill, you must conduct separate performance tests while the raw mill is operating (''mill on'') and while the raw mill is not operating (''mill off''). Using the fraction of time the raw mill is on and the fraction of time that the raw mill is off, calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off compliance testing with Equation 15.

$$R=(y*t)+(x*(1-t)) \qquad \text{(Eq.15)}$$

Where:

R = Operating limit as THC, ppmvw.

y = Average THC CEMS value during mill on operations, ppmvw.

t = Percentage of operating time with mill on.

x = Average THC CEMS value during mill off operations, ppmvw.

(1-t) = Percentage of operating time with mill off.

(x) To determine continuous compliance with the THC operating limit, you must record the THC CEMS output data for all periods when the process is operating and the THC CEMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the THC CEMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (ppmvw) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 16 to determine the 30 kiln operating day average.

$$30\text{kiln operating day} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{(Eq. 16)}$$

Where:

Hpvi = The hourly parameter value for hour i, ppmvw.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

(xi) Use EPA Method 18 or Method 320 of appendix A to part 60 of this chapter to determine organic HAP emissions. For each performance test, conduct at least three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. If your source has an in-line kiln/raw mill you must conduct three separate test runs with the raw mill on, and three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur with the mill off. Conduct each Method 18 test run to collect a minimum target sample equivalent to three times the method detection limit. Calculate the average of the results from three runs to determine compliance.

(xii) If the THC level exceeds by 10 percent or more your site-specific THC emissions limit, you must

(A) As soon as possible but no later than 30 days after the exceedance, conduct an inspection and take corrective action to return the THC CEMS measurements to within the established value; and

(B) Within 90 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct another performance test to determine compliance with the organic HAP limit and to verify or re-establish your site-specific THC emissions limit.

(8) HCl Emissions Tests with SO_2 Monitoring. If you choose to monitor SO_2 emissions using a CEMS to demonstrate HCl compliance, follow the procedures in (b)(8)(i) through (ix) of this section and in accordance with the requirements of § 63.1350(l)(3). You must establish an SO_2 operating limit equal to the average of the SO_2 emissions recorded during the HCl stack test. This operating limit will apply only for demonstrating HCl compliance.

(i) Use Method 321 of appendix A to this part to determine emissions of HCl. Each performance test must consist of three separate runs under the conditions that exist when the affected source is operating at the representative performance conditions in accordance with § 63.7(e). Each run must be conducted for at least one hour.

(ii) At the same time that you are conducting the performance test for HCl, you must also determine a site-specific SO_2 emissions limit by

operating an SO_2 CEMS in accordance with the requirements of § 63.1350(l). The duration of the performance test must be three hours and the average SO_2 concentration (as calculated from the 1-minute averages) during the 3-hour test must be calculated. You must establish your SO_2 operating limit and determine compliance with it according to paragraphs (b)(8)(vii) and (viii)of this section.

(iii) If your source has an in-line kiln/raw mill you must use the fraction of time the raw mill is on and the fraction of time that the raw mill is off and calculate this limit as a weighted average of the SO_2 levels measured during raw mill on and raw mill off testing.

(iv) Your SO_2 CEMS must be calibrated and operated according to the requirements of § 60.63(f).

(v) Your SO_2 CEMS measurement scale must be capable of reading SO_2 concentrations consistent with the requirements of § 60.63(f), including mill on or mill off operation.

(vi) If your kiln has an inline kiln/raw mill, you must conduct separate performance tests while the raw mill is operating (''mill on'') and while the raw mill is not operating (''mill off''). Using the fraction of time the raw mill is on and the fraction of time that the raw mill is off, calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off compliance testing with Equation 17.

$$R=(y*t)+x*(t-1) \qquad \text{(Eq. 17)}$$

Where:

R = Operating limit as SO_2, ppmvw.

y = Average SO_2 CEMS value during mill on operations, ppmvw.

t = Percentage of operating time with mill on, expressed as a decimal.

x = Average SO_2 CEMS value during mill off operations, ppmvw.

t − 1 = Percentage of operating time with mill off, expressed as a decimal.

(vii) To determine continuous compliance with the SO_2 operating limit, you must record the SO_2 CEMS output data for all periods when the process is operating and the SO_2 CEMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the SO_2 CEMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (ppmvw) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 18 to determine the 30 kiln operating day average.

$$30\text{kiln operating day} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{(Eq. 18)}$$

Where:

Hpvi = The hourly parameter value for hour i, ppmvw.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

(viii) Use EPA Method 321 of appendix A to part 60 of this chapter to determine HCl emissions. For each performance test, conduct at least three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. If your source has an in-line kiln/raw mill you must conduct three separate test runs with the raw mill on, and three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur with the mill off.

(ix) If the SO_2 level exceeds by 10 percent or more your site-specific SO_2 emissions limit, you must

(A) As soon as possible but no later than 30 days after the exceedance, conduct an inspection and take corrective action to return the SO_2 CEMS measurements to within the established value. and

(B) Within 90 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct another performance test to determine compliance with the HCl limit and to verify or re-establish your site-specific SO_2 emissions limit.

(c) *Performance Test Frequency.* Except as provided in § 63.1348(b), performance tests are required at regular intervals for affected sources that are subject to a dioxin, organic HAP or HCl emissions limit and must be repeated every 30 months except for pollutants where that specific pollutant is monitored using CEMS. Tests for PM are repeated every 12 months.

(d) *Performance Test Reporting Requirements.* (1) You must submit the information specified in paragraphs (d)(1) and (2) of this section no later than 60 days following the initial performance test. All reports must be signed by a responsible official.

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(ii) The values for the site-specific operating limits or parameters established pursuant to paragraphs (b)(1), (3), (6), and (7) of this section, as applicable, and a description, including sample calculations, of how the operating parameters were established during the initial performance test.

(2) As of December 31, 2011 and within 60 days after the date of completing each performance evaluation or test, as defined in § 63.2, conducted to demonstrate compliance with any standard covered by this subpart, you must submit the relative accuracy test audit data and performance test data, except opacity data, to the EPA by successfully submitting the data electronically to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool(ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*).

(e) *Conditions of performance tests.* Conduct performance tests under such conditions as the Administrator specifies to the owner or operator based on representative performance of the affected source for the period being tested. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

■ 18. Section 63.1350 is amended by:

■ a. Revising paragraphs (a) through (d);

■ b. Revising paragraph (f) introductory text;

■ c. Revising paragraphs (f)(1)(iv) through (f)(1)(vi);
■ d. Revising paragraphs (f)(2)(i) and (f)(2)(iii);
■ e. Revising paragraphs (f)(3) and (f)(4);
■ f. Revising paragraph (g)(1) introductory text;
■ g. Revising paragraphs (g)(2) and (g)(4);
■ h. Revising paragraph (h)(1)(ii);
■ i. Revising paragraphs (i)(1) and (i)(2);
■ j. Revising paragraph (k);
■ k. Revising paragraph (l);
■ l. Revising paragraph (m) introductory text;
■ m. Revising paragraphs (m)(3) and (m)(7)(i);
■ n. Revising introductory text for paragraphs (m)(9) and (m) (10);
■ o. Revising paragraph (m)(10)(i) through (m)(10)(vii), and paragraph (m)(11)(v);
■ p. Revising introductory text for paragraphs (n), (o), and (p);
■ q. Removing and reserving paragraph (n)(3); and
■ r. Revising introductory text for paragraphs (p)(1), (p)(2), and (p)(5).

The revisions and additions read as follows:

§ 63.1350 Monitoring requirements.

(a)(1) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of this section.

(2) All continuous monitoring data for periods of startup and shutdown must be compiled and averaged separately from data gathered during other operating periods.

(3) For each existing unit that is equipped with a CMS, maintain the average emissions or the operating parameter values within the operating parameter limits established through performance tests.

(4) Any instance where the owner or operator fails to comply with the continuous monitoring requirements of this section is a violation.

(b) *PM monitoring requirements.* (1)(i) *PM CPMS.* You will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using Method 5 or Method 5I at appendix A–3 to part 60 of this chapter. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test using the procedures in § 63.1349(b)(1) (i) through (vi) of this subpart. You must also repeat the test if you change the analytical range of the instrument, or if you replace the instrument itself or any principle analytical component of the instrument that would alter the relationship of output signal to in-stack PM concentration.

(ii) To determine continuous compliance, you must use the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day.

(iii) For any exceedance of the 30 process operating day PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the exceedance, visually inspect the APCD;

(B) If inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the PM CPMS operating limit within 45 days. You are not required to conduct additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(iv) PM CPMS exceedances leading to more than four required performance tests in a 12-month process operating period (rolling monthly) constitute a presumptive violation of this subpart.

(2) [Reserved]

(c) [Reserved]

(d) *Clinker production monitoring requirements.* In order to determine clinker production, you must:

(1) Determine hourly clinker production by one of two methods:

(i) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates in tons-mass per hour of the amount of clinker produced. The system of measuring hourly clinker production must be maintained within ±5 percent accuracy, or

(ii) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates in tons-mass per hour of the amount of feed to the kiln. The system of measuring feed must be maintained within ±5 percent accuracy. Calculate your hourly clinker production rate using a kiln-specific feed to clinker ratio based on reconciled clinker production determined for accounting purposes and recorded feed rates. Update this ratio monthly. Note that if this ratio changes at clinker reconciliation, you must use the new ratio going forward, but you do not have to retroactively change clinker production rates previously estimated.

(iii) [Reserved]

(2) Determine, record, and maintain a record of the accuracy of the system of measuring hourly clinker production (or feed mass flow if applicable) before initial use (for new sources) or by the effective compliance date of this rule (for existing sources). During each quarter of source operation, you must determine, record, and maintain a record of the ongoing accuracy of the system of measuring hourly clinker production (or feed mass flow).

(3) If you measure clinker production directly, record the daily clinker production rates; if you measure the kiln feed rates and calculate clinker production, record the hourly kiln feed and clinker production rates.

(4) Develop an emissions monitoring plan in accordance with paragraphs (p)(1) through (p)(4) of this section.

* * * * *

(f) *Opacity Monitoring Requirements.* If you are subject to a limitation on opacity under § 63.1345, you must conduct required opacity monitoring in accordance with the provisions of paragraphs (f)(1)(i) through (vii) of this section and in accordance with your monitoring plan developed under § 63.1350(p). You must also develop an opacity monitoring plan in accordance with paragraphs (p)(1) through (4) and paragraph (o)(5), if applicable, of this section.

(1) * * *

(iv) If visible emissions are observed during any Method 22 performance test, of appendix A–7 to part 60 of this chapter, you must conduct 30 minutes of opacity observations, recorded at 15-second intervals, in accordance with Method 9 of appendix A–4 to part 60 of this chapter. The Method 9 performance test, of appendix A–4 to part 60 of this chapter, must begin within 1 hour of any observation of visible emissions.

(v) Any totally enclosed conveying system transfer point, regardless of the location of the transfer point is not required to conduct Method 22 visible emissions monitoring under this

paragraph. The enclosures for these transfer points must be operated and maintained as total enclosures on a continuing basis in accordance with the facility operations and maintenance plan.

(vi) If any partially enclosed or unenclosed conveying system transfer point is located in a building, you must conduct a Method 22 performance test, of appendix A–7 to part 60 of this chapter, according to the requirements of paragraphs (f)(1)(i) through (iv) of this section for each such conveying system transfer point located within the building, or for the building itself, according to paragraph (f)(1)(vii) of this section.

* * * * *

(2)(i) For a raw mill or finish mill, you must monitor opacity by conducting daily visible emissions observations of the mill sweep and air separator PM control devices (PMCD) of these affected sources in accordance with the procedures of Method 22 of appendix A–7 to part 60 of this chapter. The duration of the Method 22 performance test must be 6 minutes.

* * * * *

(iii) If visible emissions are observed during the follow-up Method 22 performance test required by paragraph (f)(2)(ii) of this section from any stack from which visible emissions were observed during the previous Method 22 performance test required by paragraph (f)(2)(i) of the section, you must then conduct an opacity test of each stack from which emissions were observed during the follow up Method 22 performance test in accordance with Method 9 of appendix A–4 to part 60 of this chapter. The duration of the Method 9 test must be 30 minutes.

(3) If visible emissions are observed during any Method 22 visible emissions test conducted under paragraphs (f)(1) or (2) of this section, you must initiate, within one-hour, the corrective actions specified in your operation and maintenance plan as required in § 63.1347.

(4) The requirements under paragraph (f)(2) of this section to conduct daily Method 22 testing do not apply to any specific raw mill or finish mill equipped with a COMS or BLDS.

(i) If the owner or operator chooses to install a COMS in lieu of conducting the daily visible emissions testing required under paragraph (f)(2) of this section, then the COMS must be installed at the outlet of the PM control device of the raw mill or finish mill and the COMS must be installed, maintained, calibrated, and operated as required by the general provisions in subpart A of this part and according to PS–1 of appendix B to part 60 of this chapter.

(ii) If you choose to install a BLDS in lieu of conducting the daily visible emissions testing required under paragraph (f)(2) of this section, the requirements in paragraphs (m)(1) through (m)(4), (m)(10) and (m)(11) of this section apply.

(g) * * *

(1) You must install, calibrate, maintain, and continuously operate a CMS to record the temperature of the exhaust gases from the kiln and alkali bypass, if applicable, at the inlet to, or upstream of, the kiln and/or alkali bypass PMCDs.

* * * * *

(2) You must monitor and continuously record the temperature of the exhaust gases from the kiln and alkali bypass, if applicable, at the inlet to the kiln and/or alkali bypass PMCD.

* * * * *

(4) Calculate the rolling three-hour average temperature using the average of 180 successive one-minute average temperatures. See § 63.1349(b)(3).

* * * * *

(h) * * *

(1) * * *

(ii) Each hour, calculate the three-hour rolling average activated carbon injection rate for the previous three hours of process operation. See § 63.1349(b)(3).

* * * * *

(i) * * *

(1) You must install, operate, and maintain a THC continuous emission monitoring system in accordance with Performance Specification 8A of appendix B to part 60 of this chapter and comply with all of the requirements for continuous monitoring systems found in the general provisions, subpart A of this part. The owner or operator must operate and maintain each CEMS according to the quality assurance requirements in Procedure 1 of appendix F in part 60 of this chapter.

(2) Performance tests on alkali bypass and coal mill stacks must be conducted using Method 25A in appendix A to 40 CFR part 60 and repeated annually.

* * * * *

(k) *Mercury Monitoring Requirements.* If you have a kiln subject to an emissions limitation on mercury emissions, you must install and operate a mercury continuous emissions monitoring system (Hg CEMS) in accordance with Performance Specification 12A (PS 12A) of appendix B to part 60 of this chapter or an integrated sorbent trap monitoring system in accordance with Performance Specification 12B (PS 12B) of appendix B to part 60 of this chapter. You must monitor mercury continuously according to paragraphs (k)(1) through (5) of this section. You must also develop an emissions monitoring plan in accordance with paragraphs (p)(1) through (4) of this section.

(1) You must use a span value for any Hg CEMS that represents the mercury concentration corresponding to approximately two times the emissions standard and may be rounded up to the nearest multiple of 5 μg/m³ of total mercury or higher level if necessary to include Hg concentrations which may occur (excluding concentrations during in-line raw ''mill off'' operation). As specified in PS 12A, Section 6.1.1, the data recorder output range must include the full range of expected Hg concentration values which would include those expected during ''mill off'' conditions. Engineering judgments made and calculations used to determine the corresponding span concentration from the emission standard shall be documented in the site-specific monitoring plan and associated records.

(2) In order to quality assure data measured above the span value, you must use one of the two options in paragraphs (k)(2)(i) and (ii) of this section.

(i) Include a second span that encompasses the Hg emission concentrations expected to be encountered during ''mill off'' conditions. This second span may be rounded to a multiple of 5 μg/m³ of total mercury. The requirements of PS 12A, shall be followed for this second span with the exception that a RATA with the mill off is not required.

(ii) Quality assure any data above the span value established in paragraph (k)(1) of this section using the following procedure. Any time two consecutive one-hour average measured concentration of Hg exceeds the span value you must, within 24 hours before or after, introduce a higher, ''above span'' Hg reference gas standard to the Hg CEMS. The ''above span'' reference gas must meet the requirements of PS 12A, Section 7.1, must be of a concentration level between 50 and 150 percent of the highest hourly concentration measured during the period of measurements above span, and must be introduced at the probe. Record and report the results of this procedure as you would for a daily calibration. The ''above span'' calibration is successful if the value measured by the Hg CEMS is within 20 percent of the certified value of the reference gas. If the value measured by the Hg CEMS exceeds 20 percent of the

certified value of the reference gas, then you must normalize the one-hour average stack gas values measured above the span during the 24-hour period preceding or following the ''above span'' calibration for reporting based on the Hg CEMS response to the reference gas as shown in equation 19:

$$\frac{\text{Certified reference gas value}}{\text{Measured value of reference gas}} \times \text{Measured stack gas result} = \text{Normalized stack gas result} \quad \text{(Eq. 19)}$$

Only one 'above span' calibration is needed per 24 hour period.

(3) You must operate and maintain each Hg CEMS or an integrated sorbent trap monitoring system according to the quality assurance requirements in Procedure 5 of appendix F to part 60 of this chapter. During the RATA of integrated sorbent trap monitoring systems required under Procedure 5, you may apply the appropriate exception for sorbent trap section 2 breakthrough in (k)(3)(i) through (iv) of this section:

(i) For stack Hg concentrations >1 μg/dscm, ≤10% of section 1 mass;

(ii) For stack Hg concentrations ≤1 μg/dscm and >0.5 μg/dscm, ≤20% of section 1 mass;

(iii) For stack Hg concentrations ≤0.5 μg/dscm and >0.1 μg/dscm, ≤50% of section 1 mass; and

(iv) For stack Hg concentrations ≤0.1 μg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

(4) Relative accuracy testing of mercury monitoring systems under PS 12A, PS 12B, or Procedure 5 must be conducted at normal operating conditions. If a facility has an inline raw mill, the testing must occur with the raw mill on.

(5) If you use a Hg CEMS or an integrated sorbent trap monitoring system, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the exhaust gas flow rate to the atmosphere according to the requirements in paragraphs (n)(1) through (10) of this section. If kiln gases are diverted through an alkali bypass or to a coal mill and exhausted through separate stacks, you must account for the mercury emitted from those stacks by following the procedures in (k)(5)(i) through (iv) of this section:

(i) Develop a mercury hourly mass emissions rate by conducting annual performance tests using Method 29, or Method 30B, to measure the concentration of mercury in the gases exhausted from the alkali bypass and coal mill.

(ii) On a continuous basis, determine the mass emissions of mercury in lb/hr from the alkali bypass and coal mill exhausts by using the mercury hourly emissions rate, the exhaust gas flow rate and hourly mercury emission rate to calculate hourly mercury emissions in lb/hr.

(iii) Sum the hourly mercury emissions from the kiln, alkali bypass and coal mill to determine total mercury emissions. Using hourly clinker production, calculate the hourly emissions rate in pounds per ton of clinker to determine your 30 day rolling average.

(iv) If mercury emissions from the coal mill are below the method detection limit for two consecutive annual performance tests, you may reduce the frequency of the performance tests of coal mills to once every 30 months. If the measured mercury concentration exceeds the method detection limit, you must revert to testing annually until two consecutive annual tests are below the method detection limit.

(6) If you operate an integrated sorbent trap monitoring system conforming to PS 12B, you may use a monitoring period at least 24 hours but no longer than 168 hours in length. You should use a monitoring period that is a multiple of 24 hours (except during relative accuracy testing as allowed in PS 12B).

(l) *HCl Monitoring Requirements.* If you are subject to an emissions limitation on HCl emissions in § 63.1343, you must monitor HCl emissions continuously according to paragraph (l)(1) or (2) and paragraphs (m)(1) through (4) of this section or, if your kiln is controlled using a wet or dry scrubber or tray tower, you alternatively may parametrically monitor SO_2 emissions continuously according to paragraph (l)(3) of this section. You must also develop an emissions monitoring plan in accordance with paragraphs (p)(1) through (4) of this section.

(1) If you monitor compliance with the HCl emissions limit by operating an HCl CEMS, you must do so in accordance with Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, or, upon promulgation, in accordance with any other performance specification for HCl CEMS in appendix B to part 60 of this chapter. You must operate, maintain, and quality assure a HCl CEMS installed and certified under PS 15 according to the quality assurance requirements in Procedure 1 of appendix F to part 60 of this chapter except that the Relative Accuracy Test Audit requirements of Procedure 1 must be replaced with the validation requirements and criteria of sections 11.1.1 and 12.0 of PS 15. If you install and operate an HCl CEMS in accordance with any other performance specification for HCl CEMS in appendix B to part 60 of this chapter, you must operate, maintain and quality assure the HCl CEMS using the procedure of appendix F to part 60 of this chapter applicable to the performance specification. You must use Method 321 of appendix A to part 63 of this chapter as the reference test method for conducting relative accuracy testing. The span value and calibration requirements in paragraphs (l)(1)(i) and (ii) of this section apply to HCl CEMS other than those installed and certified under PS 15.

(i) You must use a span value for any HCl CEMS that represents the intended upper limit of the HCl concentration measurement range during normal inline raw ''mill on'' operation. The span value should be a concentration equivalent to approximately two times the emissions standard and it may be rounded to the nearest multiple of 5 ppm of HCl. The HCl CEMS data recorder output range must include the full range of expected HCl concentration values which would include those expected during ''mill off'' conditions. Engineering judgments made and calculations used to determine the corresponding span concentration from the emission standard shall be documented in the site-specific monitoring plan and associated records.

(ii) In order to quality assure data measured above the span value, you must use one of the two options in paragraphs (l)(1)(ii)(A) and (B) of this section.

(A) Include a second span that encompasses the HCl emission concentrations expected to be

encountered during ''mill off'' conditions. This second span may be rounded to a multiple of 5 μg/m³ of total HCl. The requirements of the appropriate HCl monitor performance specification, shall be followed for this second span with the exception that a RATA with the mill off is not required.

(B) Quality assure any data above the span value established in paragraph (1)(1)(i) of this section using the following procedure. Any time the average measured concentration of HCl exceeds or is expected to exceed the span value for greater than two hours you must, within a period 24 hours before or after the 'above span' period, introduce a higher, 'above span' HCl reference gas standard to the HCl CEMS. The 'above span' reference gas must meet the requirements of the applicable performance specification and be of a concentration level between 50 and 100 percent of the highest hourly concentration measured during the period of measurements above span, and must be introduced at the probe. Record and report the results of this procedure as you would for a daily calibration. The 'above span' calibration is successful if the value measured by the HCl CEMS is within 20 percent of the certified value of the reference gas. If the value measured by the HCl CEMS is not within 20 percent of the certified value of the reference gas, then you must normalize the stack gas values measured above span as described in paragraph (l)(1)(ii)(C) below. If the 'above span' calibration is conducted during the period when measured emissions are above span and there is a failure to collect the required minimum number of data points in an hour due to the calibration duration, then you must determine the emissions average for that missed hour as the average of hourly averages for the hour preceding the missed hour and the hour following the missed hour.

(C) In the event that the 'above span' calibration is not successful (i.e., the HCl CEMS measured value is not within 20 percent of the certified value of the reference gas), then you must normalize the one-hour average stack gas values measured above the span during the 24-hour period preceding or following the 'above span' calibration for reporting based on the HCl CEMS response to the reference gas as shown in Equation 20:

$$\frac{\text{Certified reference gas value}}{\text{Measured value of reference gas}} \times \text{Measured stack gas result} = \text{Normalized stack gas result} \qquad \text{(Eq. 20)}$$

Only one 'above span' calibration is needed per 24-hour period.

(2) Install, operate, and maintain a CMS to monitor wet scrubber or tray tower parameters, as specified in paragraphs (m)(5) and (7) of this section, and dry scrubber, as specified in paragraph (m)(9) of this section.

(3) If the source is equipped with a wet or dry scrubber or tray tower, and you choose to monitor SO_2 emissions, monitor SO_2 emissions continuously according to the requirements of § 60.63(e) through (f) of part 60 subpart F of this chapter. If SO_2 levels increase above the 30-day rolling average SO_2 operating limit established during your performance test, you must:

(i) As soon as possible but no later than 48 hours after you exceed the established SO_2 value conduct an inspection and take corrective action to return the SO_2 emissions to within the operating limit; and

(ii) Within 60 days of the exceedance or at the time of the next compliance test, whichever comes first, conduct an HCl emissions compliance test to determine compliance with the HCl emissions limit and to verify or re-establish the SO_2 CEMS operating limit.

(m) *Parameter Monitoring Requirements.* If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (m)(1) through (4) of this section by the compliance date specified in § 63.1351. You must also meet the applicable specific parameter monitoring requirements in paragraphs (m)(5) through (11) that are applicable to you.

* * * * *

(3) Determine the 1-hour block average of all recorded readings.

* * * * *

(7) * * *

(i) Locate the pH sensor in a position that provides a representative measurement of wet scrubber or tray tower effluent pH.

* * * * *

(9) *Mass Flow Rate (for Sorbent Injection) Monitoring Requirements.* If you have an operating limit that requires the use of equipment to monitor sorbent injection rate (*e.g.,* weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (m)(9)(i) through (iii) of this section. These requirements also apply to the sorbent injection equipment of a dry scrubber.

* * * * *

(10) *Bag leak detection monitoring requirements.* If you elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate a BLDS as specified in paragraphs (m)(10)(i) through (viii) of this section.

(i) You must install and operate a BLDS for each exhaust stack of the fabric filter.

(ii) Each BLDS must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(iii) The BLDS must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 or fewer milligrams per actual cubic meter.

(iv) The BLDS sensor must provide output of relative or absolute PM loadings.

(v) The BLDS must be equipped with a device to continuously record the output signal from the sensor.

(vi) The BLDS must be equipped with an alarm system that will alert an operator automatically when an increase in relative PM emissions over a preset level is detected. The alarm must be located such that the alert is detected and recognized easily by an operator.

(vii) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a BLDS must be installed in each baghouse compartment or cell.

* * * * *

(11) * * *

(v) Cleaning the BLDS probe or otherwise repairing the BLDS; or

* * * * *

(n) *Continuous Flow Rate Monitoring System.* You must install, operate, calibrate, and maintain instruments, according to the requirements in

paragraphs (n)(1) through (10) of this section, for continuously measuring and recording the stack gas flow rate to allow determination of the pollutant mass emissions rate to the atmosphere from sources subject to an emissions limitation that has a pounds per ton of clinker unit.

* * * * *

(o) *Alternate Monitoring Requirements Approval.* You may submit an application to the Administrator for approval of alternate monitoring requirements to demonstrate compliance with the emission standards of this subpart, except for emission standards for THC, subject to the provisions of paragraphs (o)(1) through (6) of this section.

* * * * *

(p) *Development and Submittal (Upon Request) of Monitoring Plans.* If you demonstrate compliance with any applicable emissions limit through performance stack testing or other emissions monitoring, you must develop a site-specific monitoring plan according to the requirements in paragraphs (p)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under paragraph (o) of this section and § 63.8(f). If you use a BLDS, you must also meet the requirements specified in paragraph (p)(5) of this section.

(1) For each CMS required in this section, you must develop, and submit to the permitting authority for approval upon request, a site-specific monitoring plan that addresses paragraphs (p)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 30 days before your initial performance evaluation of your CMS.

* * * * *

(2) In your site-specific monitoring plan, you must also address paragraphs (p)(2)(i) through (iii) of this section.

* * * * *

(5) *BLDS Monitoring Plan.* Each monitoring plan must describe the items in paragraphs (p)(5)(i) through (v) of this section. At a minimum, you must retain records related to the site-specific monitoring plan and information discussed in paragraphs (m)(1) through (4), (m)(10) and (11) of this section for a period of 5 years, with at least the first 2 years on-site;

* * * * *

■ 19. Section 63.1351 is amended by revising paragraphs (c) and (d) and adding paragraph (e) to read as follows:

§ 63.1351 Compliance dates.

* * * * *

(c) The compliance date for existing sources for all the requirements that became effective on February 12, 2013, except for the open clinker pile requirements will be September 9, 2015.

(d) The compliance date for new sources is February 12, 2013, or startup, whichever is later.

(e) The compliance date for existing sources with the requirements for open clinker storage piles in § 63.1343(c) is February 12, 2014.

■ 20. Section 63.1352 is amended by revising paragraph (b) to read as follows:

§ 63.1352 Additional test methods.

* * * * *

(b) Owners or operators conducting tests to determine the rates of emission of specific organic HAP from raw material dryers, and kilns at Portland cement manufacturing facilities, solely for use in applicability determinations under § 63.1340 of this subpart are permitted to use Method 320 of appendix A to this part, or Method 18 of appendix A to part 60 of this chapter.

■ 21. Section 63.1353 is amended by adding paragraph (b)(6) to read as follows:

§ 63.1353 Notification Requirements.

* * * * *

(b) * * *

(6) Within 48 hours of an exceedance that triggers retesting to establish compliance and new operating limits, notify the appropriate permitting agency of the planned performance tests. The notification requirements of §§ 63.7(b) and 63.9(e) do not apply to retesting required for exceedances under this subpart.

■ 22. Section 63.1354 is amended by:

■ a. Removing and reserving paragraphs (b)(4) and (5);

■ b. Revising paragraph (b)(9)(vi);

■ c. Adding paragraph (b)(9)(vii); and

■ d. Revising paragraph (c).

The revisions read as follows:

§ 63.1354 Reporting requirements.

* * * * *

(b) * * *

(9) * * *

(vi) For each PM, HCl, Hg, and THC CEMS or Hg sorbent trap monitoring system, within 60 days after the reporting periods, you must submit reports to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with the EPA's reporting form output format. For each reporting period, the reports must include all of the calculated 30-operating day rolling average values derived from the CEMS or Hg sorbent trap monitoring systems.

(vii) In response to each violation of an emissions standard or established operating parameter limit, the date, duration and description of each violation and the specific actions taken for each violation including inspections, corrective actions and repeat performance tests and the results of those actions.

* * * * *

(c) Reporting a failure to meet a standard due to a malfunction. For each failure to meet a standard or emissions limit caused by a malfunction at an affected source, you must report the failure in the semi-annual compliance report required by § 63.1354(b)(9). The report must contain the date, time and duration, and the cause of each event (including unknown cause, if applicable), and a sum of the number of events in the reporting period. The report must list for each event the affected source or equipment, an estimate of the volume of each regulated pollutant emitted over the emission limit for which the source failed to meet a standard, and a description of the method used to estimate the emissions. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.1348(d), including actions taken to correct a malfunction.

■ 23. Section 63.1355 is amended by revising paragraphs (f) and (g)(1) and adding paragraph (h) to read as follows:

§ 63.1355 Recordkeeping Requirements.

* * * * *

(f) You must keep records of the date, time and duration of each startup or shutdown period for any affected source that is subject to a standard during startup or shutdown that differs from the standard applicable at other times, and the quantity of feed and fuel used during the startup or shutdown period.

(g)(1) You must keep records of the date, time and duration of each malfunction that causes an affected source to fail to meet an applicable standard; if there was also a monitoring malfunction, the date, time and duration of the monitoring malfunction; the record must list the affected source or equipment, an estimate of the volume of each regulated pollutant emitted over the standard for which the source failed to meet a standard, and a description of

the method used to estimate the emissions.

* * * * *

(h) For each exceedance from an emissions standard or established operating parameter limit, you must keep records of the date, duration and description of each exceedance and the specific actions taken for each exceedance including inspections, corrective actions and repeat performance tests and the results of those actions.

■ 24. Section 63.1356 is revised to read as follows:

§ 63.1356 Sources with multiple emissions limit or monitoring requirements.

If an affected facility subject to this subpart has a different emissions limit or requirement for the same pollutant under another regulation in title 40 of this chapter, the owner or operator of the affected facility must comply with the most stringent emissions limit or requirement and is exempt from the less stringent requirement.

■ 25. Section 63.1357 is amended by revising paragraphs (a)(1) and (2) to read as follows:

§ 63.1357 Temporary, conditioned exemption from particulate matter and opacity standards.

(a) * * *

(1) Any PM and opacity standards of part 60 or part 63 of this chapter that are applicable to cement kilns and clinker coolers.

(2) Any permit or other emissions or operating parameter or other limitation on workplace practices that are applicable to cement kilns and clinker coolers to ensure compliance with any PM and opacity standards of this part or part 60 of this chapter.

* * * * *

■ 26. Table 3 to Subpart LLL of Part 63 is revised by revising the entries for 63.6(e)(3), 63.7(b), and 63.9(e) to read as follows:

TABLE 3—TO SUBPART LLL OF PART 63—APPLICABILITY OF GENERAL PROVISIONS

Citation	Requirement	Applies to Subpart LLL	Explanation
*	*	*	*
63.6(e)(3)	Startup, Shutdown Malfunction Plan	No	Your operations and maintenance plan must address periods of startup and shutdown. See § 63.1347(a)(1).
*	*	*	*
63.7(b)	Notification period	Yes	Except for repeat performance test caused by an exceedance. See § 63.1353(b)(6)
*	*	*	*
63.9(e)	Notification of performance test	Yes	Except for repeat performance test caused by an exceedance. See § 63.1353(b)(6)
*	*	*	*

[FR Doc. 2012–31633 Filed 2–11–13; 8:45 am]

BILLING CODE 6560–50–P

[FR Doc. 2013–05112 Filed 3–5–13; 8:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2008–0708, FRL–9756–4]

RIN 2060–AQ58

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines

Correction

In rule document 2013–01288, appearing on pages 6674–6724 in the issue of Wednesday, January 30, 2013, make the following corrections:

§ 63.6655 [Corrected]

■ 1. On page 6708, the heading in Table 2c to Subpart ZZZZ of Part 63 is corrected 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

■ 2. On page 6708, in the first column of Table 2c to Subpart ZZZZ of Part 63, the entry reading ''4. Non-Emergency, non-black start CI stationary RICE 300>HP≤500.'' is corrected to read ''4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500.''

■ 3. On page 6709, the heading in Table 2c to Subpart ZZZZ of Part 63 is corrected 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—Continued

[FR Doc. C1–2013–01288 Filed 3–5–13; 8:45 am]
BILLING CODE 1505–01–D

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 136

[EPA–HQ–OW–2010–0192; FRL–9787–7]

Guidelines Establishing Test Procedures for the Analysis of Pollutants Under the Clean Water Act; Analysis and Sampling Procedures; Notice

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of final decision.

SUMMARY: EPA discussed, but did not propose, a new method, ASTM D7575, for oil and grease in the 2010 proposed Methods Update Rule (MUR). Oil and grease is a method-defined parameter. That is, the nature and amount of material determined by the method is defined in terms of the method. EPA subsequently published a Notice of Data Availability (NODA) on this method that provided new data and requested comment on whether and how EPA should approve the method in Part 136 as an alternative oil and grease method. This document provides EPA's final decision on its reconsideration of this method.

DATES: March 6, 2013.

FOR FURTHER INFORMATION CONTACT: Jan Matuszko, Office of Science and Technology, Office of Water (4303–T), Environmental Protection Agency, 1200 Pennsylvania Avenue NW.; Washington, DC 20460; telephone number: 202–566–1035; fax number: 202–566–1053; email address: *matuszko.jan@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

A. CWA Analytical Methods and Limited Use Alternate Test Procedures (ATP) Program

EPA establishes test procedures (also referred to as analytical methods) codified in 40 CFR Part 136 under its authority in section 304(h) of the CWA to promulgate guidelines establishing test procedures for the analysis of pollutants. EPA's regulations provide that, when EPA has promulgated a test procedure for analysis of a specific pollutant in 40 CFR Part 136, an NPDES permittee must use an approved test procedure for the specific pollutant when measuring the pollutant for an application submitted to EPA or to a State with an approved NPDES program and for reports required to be submitted by dischargers under the NPDES program. See 40 CFR § 136.1(a). This approach simplifies the permitting process for hundreds of thousands of NPDES and indirect discharging permittees and permitting authorities. In the absence of an approved test procedure for a specific pollutant (or when an approved test procedure does not work in a specific matrix, e.g., because of a matrix interference), generally, a permit applicant may use any suitable method but must provide the permitting authority a description of the method for evaluation of its suitability. See 40 CFR 122.21(g)(7). However, 40 CFR Part 136 also recognizes that new technologies and approaches are constantly being developed, including methods for pollutants for which EPA already has an approved test procedure. As such, Part 136.5 allows for use of an alternate method for a specific pollutant or parameter in a regulated CWA matrix that is different from the approved test procedure (i.e., limited use approval). Requests for such uses, along with supporting data, are made to the applicable Regional Alternate Test Procedure (ATP) Coordinator for consideration and approval.

B. Oil and Grease

Unlike many parameters, oil and grease is not a unique chemical entity, but is a mixture of chemical species that varies from source to source. Common substances that may contribute to oil and grease include petroleum based compounds such as fuels, motor oil, lubricating oil, soaps, waxes, and hydraulic oil and vegetable based compounds such as cooking oil and other fats. Oil and grease is defined by the method used to measure it (i.e., it is a method-defined analyte). The CWA defines oil and grease as a conventional parameter and hundreds of thousands of NPDES permits and indirect discharging permits contain oil and grease numerical limits. Currently, Part 136 lists two analytical methodologies for the measurement of oil and grease in such discharge permits. Permittees have been using EPA Method 1664A to measure compliance with such discharge limits. Method 1664A is a liquid/liquid extraction (LLE), gravimetric procedure that employs normal hexane (*n*-hexane) as the extraction solvent that is applicable for measuring oil and grease in concentrations from 5 mg/L to 1,000 mg/L. This method also allows the use of solid-phase extraction (SPE) provided that the results obtained by SPE are equivalent to the results obtained by LLE.

C. Method-Defined Analytes

The measurement results obtained for a method-defined analyte are both

■ 2. § 52.720 is amended by adding paragraph (c)(194) to read as follows:

§ 52.720 Identification of plan.

* * * * *

(c) * * *

(194) On November 14, 2011, the Illinois Environmental Protection Agency (Illinois EPA) submitted amendments to 35 Illinois Administrative Code 218.208 and 219.208. These sections add a ''small container exemption'' for pleasure craft surface coating operations in the Chicago and Metro-East St. Louis 8-hour ozone nonattainment areas. These exemptions are consistent with EPA volatile organic compound (VOC) reasonably available control technology (RACT) policy.

(i) Incorporation by reference. The following sections of Illinois Administrative Code, Title 35: Environmental Protection, Subtitle B: Air Pollution, Chapter 1: Pollution Control Board, Subchapter c: Emission Standards and Limitations for Stationary Sources, are incorporated by reference.

(A) Part 218: Organic Material Emission Standards and Limitations for the Chicago Area, Subpart F: Coating Operations, Section 218.208 Exemptions From Emission Limitations; effective October 25, 2011.

(B) Part 219: Organic Material Emission Standards and Limitations for the Metro East Area, Subpart F: Coating Operations, Section 219.208 Exemptions From Emission Limitations; effective October 25, 2011.

[FR Doc. 2013–08948 Filed 4–18–13; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2010–0600; FRL–9801–4]

RIN 2060–AQ60

Reconsideration Petition From the National Association of Surface Finishers for the National Emission Standards for Hazardous Air Pollutant Emissions: Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks; and Steel Pickling—HCl Process Facilities and Hydrochloric Acid Regeneration Plants

AGENCY: Environmental Protection Agency EPA).

ACTION: Notice of Final Action Denying Petition for Reconsideration.

SUMMARY: This action provides notice that on March 28, 2013, the Acting EPA Administrator, Bob Perciasepe, signed a letter denying a petition for reconsideration of the final rule published in the **Federal Register** on September 19, 2012. The rule established new emission limits for hard and decorative chromium electroplating and chromium anodizing tanks, and steel pickling—HCl process facilities and hydrochloric acid regeneration plants.

DATES: *Effective:* April 19, 2013.

Petitions: Any petitions for review of the letter and enclosure denying the petition for reconsideration described in this document must be filed in the Court of Appeals for the District of Columbia Circuit by June 18, 2013.

FOR FURTHER INFORMATION CONTACT: Mr. Phil Mulrine, Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5289; fax number: (919) 541–3207; email address: *mulrine.phil@epa.gov.*

SUPPLEMENTARY INFORMATION:

Description of Action: The EPA is providing notice that it has denied a petition for reconsideration of a final rule published in the **Federal Register** on September 19, 2012. The rule established new emission limits for hard and decorative chromium electroplating and chromium anodizing tanks, and steel pickling—HCl process facilities and hydrochloric acid regeneration plants, and was issued pursuant to the EPA's authority under sections 112(d)(6) and (f)(2) of the Clean Air Act (CAA). After publication of the rule, the EPA received a petition for reconsideration of the final rule from the National Association of Surface Finishers (NASF). After carefully considering the petition and supporting information, the Acting EPA Administrator, Bob Perciasepe, denied the petition for reconsideration on March 28, 2013, in a letter to the petitioner. The EPA denied the petition because it failed to meet the criteria for reconsideration in CAA section 307(d)(7)(B). The letter and an accompanying enclosure explain in detail the EPA's reasons for the denial.

I. How can I get copies of this document and other related information?

This **Federal Register** notice, the petition for reconsideration and the letter denying the petition for reconsideration are available in the docket that the EPA established under Docket ID No. EPA–HQ–OAR–2010–0600. The document identification number for the petition for reconsideration is: NASF, EPA–HQ–OAR–2010–0600–0693. The document identification number for EPA's response letter is: NASF, EPA–HQ–OAR–2010–0600–0695. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the EPA Docket Center (Air Docket), EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744 and the telephone number for the Air Docket is (202) 566–1742.

This **Federal Register** notice, the petition for reconsideration and the letter denying the petition can also be found on the EPA's Web site at *http://www.epa.gov/ttn/atw/chrome/chromepg.html.*

II. Judicial Review

Any petitions for review of the letter and enclosure denying the petition for reconsideration described in this Notice must be filed in the Court of Appeals for the District of Columbia Circuit by June 18, 2013.

List of Subjects in 40 CFR Part 63

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

Dated: April 12, 2013.

Bob Perciasepe,

Acting Administrator.

[FR Doc. 2013–09304 Filed 4–18–13; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2012–0246; FRL–9381–8]

Propiconazole; Pesticide Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

minimize litigation, eliminate ambiguity, and reduce burden.

10. Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

11. Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

12. Energy Effects

This action is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

14. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA)(42 U.S.C. 4321–4370f), and have determined that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves establishing a safety zone for a fireworks display launch site and fallout area and is expected to have no impact on the water or environment. This zone is designed to protect mariners and spectators from the hazards associated with aerial fireworks displays. This rule is categorically excluded from further review under paragraph 34 (g) of Figure 2–1 of the Commandant Instruction. An environmental analysis checklist supporting this determination and a Categorical Exclusion Determination are available in the docket where indicated under **ADDRESSES**. We seek any comments or information that may lead to the discovery of a significant environmental impact from this rule.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, and Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add temporary § 165.T05–0259 to read as follows:

§ 165.T05–0259 Safety Zone; Pasquotank River; Elizabeth City, NC.

(a) *Definitions.* For the purposes of this section, Captain of the Port means the Commander, Sector North Carolina.

Representative means any Coast Guard commissioned, warrant, or petty officer who has been authorized to act on the behalf of the Captain of the Port.

(b) *Location.* The following area is a safety zone: Specified waters of the Captain of the Port, Sector North Carolina, as defined in 33 CFR 3.25–20, all waters of the Pasquotank River within a 300 yard radius of the fireworks launch barge in approximate position latitude 36°17′47″ N longitude 076°12′17″, located near Machelhe Island.

(c) *Regulations.* (1) The general regulations contained in § 165.23 of this part apply to the area described in paragraph (b) of this section.

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

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

(e) *Enforcement period.* This section will be enforced on May 18, 2013 from 8 p.m. to 11 p.m. unless cancelled earlier by the Captain of the Port.

Dated: April 12, 2013.

A. Popiel,

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

[FR Doc. 2013–09609 Filed 4–23–13; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044; FRL–9789–5]

RIN 2060–AR62

Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; notice of final action on reconsideration.

SUMMARY: The EPA is taking final action on its reconsideration of certain issues in the final rules titled, ''National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units.'' The National Emission Standards for Hazardous Air Pollutants (NESHAP) rule issued pursuant to Clean Air Act (CAA) section 112 is referred to as the Mercury and Air Toxics Standards (MATS) NESHAP, and the New Source Performance Standards rule issued pursuant to CAA section 111 is referred to as the Utility NSPS. The Administrator received petitions for reconsideration of certain aspects of the MATS NESHAP and the Utility NSPS.

On November 30, 2012, the EPA granted reconsideration of, proposed, and requested comment on a limited set of issues. We also proposed certain technical corrections to both the MATS NESHAP and the Utility NSPS. The EPA is now taking final action on the revised new source numerical standards in the MATS NESHAP and the definitional and monitoring provisions in the Utility NSPS that were addressed in the

proposed reconsideration rule. As part of this action, the EPA is also making certain technical corrections to both the MATS NESHAP and the Utility NSPS. The EPA is not taking final action on requirements applicable during periods of startup and shutdown in the MATS NESHAP or on startup and shutdown provisions related to the PM standard in the Utility NSPS.

DATES: The effective date of the rule is April 24, 2013.

Docket. The EPA established two dockets for this action: Docket ID EPA–HQ–OAR–2011–0044 (NSPS action) and Docket ID EPA–HQ–OAR–2009–0234 (MATS NESHAP action). All documents in the dockets are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available (e.g., confidential business information (CBI) or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, 1301 Constitution Avenue NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

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

SUPPLEMENTARY INFORMATION:

Outline. The information presented in this preamble is organized as follows:

I. General Information
A. Does this action apply to me?
B. How do I obtain a copy of this document?
C. Judicial Review
II. Background
III. Summary of Today's Action
IV. Summary of Final Action and Changes Since Proposal—MATS NESHAP New Source Issues
V. Summary of Final Action and Changes Since Proposal—Utility NSPS
VI. Technical Corrections and Clarifications
VII. Impacts of This Final Rule
A. Summary of Emissions Impacts, Costs and Benefits
B. What are the air impacts?
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F. What are the benefits of the final standards?
VIII. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
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E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. General Information

A. Does this action apply to me?

Categories and entities potentially affected by today's action include:

Category	NAICS code[1]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/Tribal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian country.

[1] North American Industry Classification System.
[2] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive but rather to provide a guide for readers regarding entities likely to be affected by this action. To determine whether your facility, company, business, organization, etc. would be regulated by this action, you should examine the applicability criteria in 40 CFR 60.40, 60.40Da, or 60.40c or in 40 CFR 63.9982. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

B. How do I obtain a copy of this document?

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

C. Judicial Review

Under the CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by June 24, 2013. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

II. Background

The final MATS NESHAP and the Utility NSPS rules were published in the **Federal Register** at 77 FR 9304 on

February 16, 2012. Following promulgation of the final rules, the Administrator received petitions for reconsideration of numerous provisions of both the MATS NESHAP and the Utility NSPS pursuant to CAA section 307(d)(7)(B). Copies of the MATS NESHAP petitions are provided in rulemaking docket EPA–HQ–OAR–2009–0234. Copies of the Utility NSPS petitions are provided in rulemaking docket EPA–HQ–OAR–2011–0044. On November 30, 2012, the proposal granting reconsideration of certain issues in the MATS NESHAP and Utility NSPS was published in the **Federal Register** at 77 FR 71323.

III. Summary of Today's Action

This final action amends certain provisions of the final rule issued by the EPA on February 16, 2012. Through an August 2, 2012, notice (77 FR 45967), the EPA delayed the effective date of the February 2012 MATS rule for new sources only. That stay was limited to 90 days and has since expired. The February 2012 final rule is and remains in effect for all sources.

The November 30, 2012, proposed reconsideration rule proposed: (1) Certain revised new source numerical standards in the MATS NESHAP, (2) requirements applicable during periods of startup and shutdown in the MATS NESHAP, (3) startup and shutdown provisions related to the particulate matter (PM) standard in the Utility NSPS, and (4) definitional and monitoring provisions in the Utility NSPS. We also proposed certain technical corrections to both the MATS NESHAP and the Utility NSPS. We are taking final action today on the revised numerical new source MATS NESHAP limits, the definitional and monitoring issues in the Utility NSPS, and all of the technical corrections not related to startup/shutdown issues.

This summary of the final rule reflects the changes to 40 CFR Part 63, subpart UUUUU, and 40 CFR Part 60, subpart Da (77 FR 9304; February 16, 2012) made in this regard.

As noted above, in the proposed reconsideration rule, the EPA took comment on the requirements in the MATS NESHAP applicable during startup and shutdown, including the definitions of startup and shutdown. The EPA also took comment on the startup and shutdown provisions relating to the PM standard in the Utility NSPS. The EPA received considerable comments regarding these startup and shutdown provisions, including data and information relevant to the proposed work practice standard that applies in such periods. The EPA is not taking final action on the startup and shutdown provisions at this time as it needs additional time to consider and evaluate the comments and data provided.[1] The Agency is currently reviewing all of the comments received on the startup and shutdown issues and intends to act promptly to address these issues. We note that no existing sources will have to comply with the existing source MATS standards before April 16, 2015. Further, no new sources are currently under construction and it takes years to complete construction. 77 FR 71330, fn. 7. As such, there will be sufficient time for the Agency to review the comments submitted concerning the proposed startup and shutdown provisions and take appropriate action well in advance of any new source being subject to those provisions.

As described below, on the basis of information provided since the reconsideration proposal, today's action revises certain new source numerical limits in the MATS NESHAP. Specifically, the EPA is finalizing revised hydrogen chloride (HCl), filterable PM (fPM),[2] sulfur dioxide (SO_2), lead (Pb), and selenium emission limits for all new coal-fired EGUs; the mercury (Hg) emission limit for the "unit designed for coal ≥ 8,300 Btu/lb subcategory;" fPM and SO_2 emission limits for new solid oil-derived fuel-fired EGUs; fPM emission limits for new continental liquid oil-fired EGUs; and most of the emission limits for new integrated gasification combined cycle (IGCC) units.

The fPM, HCl, and Hg limits that we are finalizing in this action are provided in table 1; the alternate limits that we are finalizing are provided in table 2.[3]

TABLE 1—REVISED EMISSION LIMITATIONS FOR NEW EGUS

Subcategory	Filterable particulate matter, lb/MWh	Hydrogen chloride, lb/MWh	Mercury, lb/GWh
New—Unit not designed for low rank virgin coal	9.0E–2	1.0E–2 [a]	3.0E–3.
New—Unit designed for low rank virgin coal	9.0E–2	1.0E–2 [a]	NR.
New—IGCC	7.0E–2 [b] 9.0E–2 [c]	2.0E–3	3.0E–3.
New—Solid oil-derived	3.0E–2	NR	NR.
New—Liquid oil—continental	3.0E–1	NR	NR.

Note: lb/MWh = pounds pollutant per megawatt-hour electric output (gross).
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross).
NR = limit not opened for reconsideration (77 FR 9304; February 16, 2012).
[a] Beyond-the-floor value.
[b] Duct burners on syngas; based on permit levels in comments received.
[c] Duct burners on natural gas; based on permit levels in comments received.

TABLE 2—REVISED ALTERNATE EMISSION LIMITATIONS FOR NEW EGUS

Subcategory/pollutant	Coal-fired EGUs	IGCC [a]	Solid oil-derived
SO_2	1.0 lb/MWh	4.0E–1 lb/MWh [b]	1.0 lb/MWh
Total non-mercury metals	NR	4.0E–1 lb/GWh	NR
Antimony, Sb	NR	2.0E–2 lb/GWh	NR
Arsenic, As	NR	2.0E–2 lb/GWh	NR

[1] The EPA is also still reviewing the other issues raised in the petitions for reconsideration and is not taking any action at this time with respect to those issues.

[2] As the final MATS rule established a filterable PM (fPM) limit, every reference in this preamble to a PM limit means filterable PM.

[3] The final rule included certain alternative limits (see 77 FR 9367–9369).

TABLE 2—REVISED ALTERNATE EMISSION LIMITATIONS FOR NEW EGUS—Continued

Subcategory/pollutant	Coal-fired EGUs	IGCC [a]	Solid oil-derived
Beryllium, Be	NR	1.0E–3 lb/GWh	NR
Cadmium, Cd	NR	2.0E–3 lb/GWh	NR
Chromium, Cr	NR	4.0E–2 lb/GWh	NR
Cobalt, Co	NR	4.0E–3 lb/GWh	NR
Lead, Pb	2.0E–2 lb/GWh	9.0E–3 lb/GWh	NR
Mercury, Hg	NA	NA	NR
Manganese, Mn	NR	2.0E–2 lb/GWh	NR
Nickel, Ni	NR	7.0E–2 lb/GWh	NR
Selenium, Se	5.0E–2 lb/GWh	3.0E–1 lb/GWh	NR

NA = not applicable.
NR = limit not opened for reconsideration (77 FR 9304; February 16, 2012).
[a] Based on best-performing similar source.
[b] Based on DOE information.

In addition, in the MATS NESHAP the EPA is removing quarterly stack testing as an option to demonstrate compliance with the new source fPM emission limits; revising the way in which an owner or operator of a new EGU who chooses to use PM continuous parameter monitoring systems (CPMS) establishes an operating limit; requiring inspections and retesting within 45 days of an exceedance of the operating limit for those new EGU owners or operators who choose to use PM CPMS as a compliance option; and finalizing the presumption of violation of the emissions limit if more than 4 emissions tests are required in a 12-month period.

The final changes to the numerical emissions limits noted above incorporate information about the variability of the best performing EGUs and more accurately reflect the capabilities of emission control equipment for new EGUs. The final changes should also address commenters' concerns that vendors of EGU emission controls had been unwilling to provide guarantees regarding the ability to meet all of the standards for new EGUs as originally finalized in February 2012.

We expect that source owners and operators will install and operate the same or similar control technologies to meet the revised standards in this reconsideration action as they would have chosen to comply with the standards in the February 2012 final rule. Consistent with CAA section 112(a)(4), we are maintaining the new source trigger date for the MATS NESHAP rule as May 3, 2011. See 77 FR 71330, fn. 7. New sources must comply with the revised MATS emission standards described in section IV below by April 24, 2013, or startup, whichever is later.

In the February 2012 final Utility NSPS rule, the EPA adopted a definition of natural gas that excludes coal-derived synthetic natural gas consistent with the definition in MATS. In the Utility NSPS reconsideration proposal, we re-proposed and requested comment on that definition. Based on review of the comments received in response to the reconsideration proposal, the EPA has concluded that the definition of natural gas in the final Utility NSPS is appropriate and, therefore, is not making any changes to that definition. We are also finalizing as proposed one conforming amendment and two amendments related to EGUs burning desulfurized coal-derived synthetic natural gas. First, we amended the definition of coal to make it clear that coal-derived synthetic natural gas is considered to be coal. In addition, in recognition of the fact that emissions from the burning of desulfurized coal-derived synthetic natural gas are very similar to those from the burning of natural gas, we amended the opacity and SO_2 monitoring provisions so that facilities burning desulfurized coal-derived synthetic natural gas will have opacity and SO_2 monitoring requirements similar to those of facilities burning natural gas. Further, we are finalizing certain revisions to the definition of IGCC in the Utility NSPS. We are also finalizing as proposed the revised procedures for calculating PM emission rates intended to make the Utility NSPS procedures consistent with those in the MATS NESHAP. We did not receive any adverse comments regarding this proposed change. Finally, we are finalizing as proposed the technical corrections to the PM standards for facilities that commenced construction before March 1, 2005, and for facilities that commence modification after May 3, 2011.

The impacts of today's revisions on the costs and the benefits of the final rule are minor. As noted above, we expect that source owners and operators will install and operate the same or similar control technologies to meet the revised standards in this action as they would have chosen to comply with the standards in the February 2012 final rule.

IV. Summary of Final Action and Changes Since Proposal—MATS NESHAP New Source Issues

After consideration of the public comments received, the EPA has made certain changes in this final action from the reconsideration proposal. We address the most significant comments in this preamble. However for a complete summary of the comments received on the issues we are finalizing today and our responses thereto, please refer to the memorandum "National Emission Standards For Hazardous Air Pollutants From Coal- And Oil-Fired Electric Utility Steam Generating Units—Reconsideration; Summary Of Public Comments And Responses" (March 2013) in rulemaking docket EPA–HQ–OAR–2009–0234.

In this action, we are finalizing certain new source emission limits for the MATS NESHAP, as discussed below.

1. Changes to Certain New Source MATS NESHAP Limits

Commenters noted that in two instances, Pb emissions from coal-fired EGUs and the fPM emissions from continental liquid oil-fired EGUs, the EPA had proposed new source emission limits that were less stringent than those in the final MATS NESHAP for the respective existing sources. This approach was inconsistent with that taken in the final MATS NESHAP.[4] Although CAA section 112(d)(3) allows existing source MACT floor limits to be less stringent than new source limits, the EPA interprets this provision as

[4] See "*National Emission Standards for Hazardous Air Pollutants (NESHAP) Maximum Achievable Control Technology (MACT) Floor Analysis for Coal- and Oil-fired Electric Utility Steam Generating Units for Final Rule,*" Docket ID EPA–HQ–OAR–2009–0234–20132, p. 13.

precluding new source limits from being less stringent than existing source limits. See CAA section 112(d)(3). Thus, for Pb emissions from coal-fired EGUs and fPM emissions from continental liquid oil-fired EGUs, the EPA is finalizing new source limits that are equivalent to the final existing-source limits.

Next, commenters noted that when evaluating SO_2 emissions data from coal-fired EGUs, the EPA had not selected the lowest emitting source upon which to base the emission limit and that its rationale for excluding certain data was unlawful and arbitrary. Although the EPA disagrees with commenters on several of the excluded data sets (i.e., some of the data sets suggested by commenters comprised only a single 3-run average for each EGU with no individual run data, making assessment of variability impossible), it agrees that it inadvertently omitted the data from Stanton Unit 10 in the proposal analyses. Stanton Unit 10 does have a lower ''lowest'' 3-run data average than does the EGU selected for the new source floor analysis (Sandow Unit 5A) in the proposed reconsideration rule.

In this final action, the EPA used the Stanton data to calculate the MACT floor using the same statistical analyses used in the proposed rule (i.e., 99 percent upper predictive limit (UPL)), and the resulting MACT floor emission limit is 1.3 pounds per megawatt-hour (lb/MWh). Because this limit is less stringent than the new source performance standard (NSPS) finalized in the Utility NSPS (77 FR 9451; February 16, 2012), the EPA is finalizing a beyond-the-floor (BTF) MACT standard of 1.0 lb/MWh, which is the same level required by the CAA section 111 NSPS for these same sources.[5] See 40 CFR 60.43Da(l)(1)(i). Cost is a required consideration in establishing CAA section 111 rules and in going BTF in establishing CAA section 112 rules. We evaluated cost in assessing whether to go BTF for this standard and concluded that it was appropriate to go BTF to a level of 1.0 lb/MWh. Moreover, the NSPS limit (also 1.0 lb/MWh) is in place and coal-fired EGUs are required to comply with that limit. As such, there is no additional cost to these sources.[6] Furthermore, we have not identified any non-air quality health or environmental impacts or energy requirements associated with the final standard set at this level. In addition, in support of the proposed reconsideration rule, we evaluated an emissions level more stringent than 1.0 lb/MWh and found that level to not be cost effective.[7] For these reasons, we are finalizing 1.0 lb/MWh as the new source MATS NESHAP limit.

In the proposed reconsideration rule, we indicated that detection level issues may arise from using a sorbent trap when short sampling periods (e.g., 30 minutes) are used. As such, the EPA solicited comment on its establishment of a Representative Detection Level (RDL) associated with Hg sorbent traps. The EPA also solicited comment on whether the UPL calculated floor should be compared against the 3XRDL value for Hg to account for the shorter sampling periods (the 3XRDL approach). The EPA received several comments, ranging from strong support for the Hg RDL and the proposed emission limit because, at that level, the commenters asserted that vendors would be able to provide commercial guarantees, to concerns about the specific inputs to the 3XRDL calculation and the application of the 3xRDL approach. See section 2.2.1 of the response to comments document (RTC) for a more complete discussion and response to these comments.

In the proposed reconsideration rule, the EPA recognized that 30 minutes of sample collection is the shortest reasonable amount of time available for collecting and changing sorbent tubes to provide the quick, reliable feedback that will allow sources to react to changing Hg emissions levels and assure compliance with the final Hg limit. Some commenters pointed out that the EPA's memorandum entitled ''Determination of Representative Detection Level (RDL) and 3 X RDL Values for Mercury Measured Using Sorbent Trap Technologies,''[8] contains a 30-minute sample collection time in the 3XRDL calculation, but the text of the memorandum references a 20-minute sample collection time. The EPA has revised the text of the memorandum to reflect its original intent, which was to focus on a sample collection period of 30 minutes (not 20 minutes). The revised memorandum focuses on the 30-minute sample collection period. Given that it takes 5 minutes for sorbent trap insertion and removal, it would take a total of 40 minutes to secure the requisite sample collection (30 minutes for sample collection, 5 minutes to remove the sorbent trap, and 5 minutes to re-insert the trap). We are finalizing the Hg limit using the 3XRDL approach assuming a 30-minute sampling time.

2. Filterable PM Testing, Monitoring, and Compliance

Certification for New EGUs in the MATS NESHAP Rule

Several monitoring options for the fPM standard for new sources were provided in the MATS NESHAP final rule, including quarterly stack testing, PM CEMS, and PM CPMS with annual testing.

The EPA sought comment on whether to retain the quarterly stack testing compliance option for new EGUs, given that continuous, direct measurement of fPM or a correlated parameter is available, is preferable for determining compliance on a continuous basis, and is likely to be used by most new EGUs to monitor compliance with the proposed new source standards. As mentioned above, this final action does not retain the quarterly fPM performance testing option for new EGUs. New EGUs can be designed to incorporate PM CEMS or PM CPMS from the outset, without being impeded by retrofit location installation constraints that could impact existing EGUs. This final action now requires new sources to use either PM CEMS or PM CPMS as options for determining compliance with the new source fPM limits.

The EPA requested comment on a number of issues associated with PM CPMS. The EPA first solicited comment on three approaches to establish an operating limit based on emissions testing for those EGU owners or operators who choose to use PM CPMS as the means of demonstrating compliance with the fPM emission limit. The first approach would require an EGU owner or operator to use the highest parameter value obtained during any run of an individual emissions test as the operating limit when the result of that individual test was below the limit. The second approach would require an EGU owner or operator to use the average parameter value obtained from

[5] The CAA section 111 standard is based on the performance of EGUs with the best performing SO_2 controls, a reasonable incremental cost effectiveness of less than $1,000 per ton of SO_2 controlled, and controls that result in minimal secondary environmental and energy impacts.

[6] The final Utility NSPS limit was not challenged and coal-fired EGUs constructed after May 3, 2011, must meet that limit.

[7] See Docket ID EPA–HQ–OAR–2009–0234–20221 and *National Emission Standards for Hazardous Air Pollutants (NESHAP) Beyond the Maximum Achievable Control Technology (MACT) Floor ('Beyond-the-Floor') Analysis for Revised Emission Standards for New Source Coal-and Oil-fired Electric Utility Steam Generating Units* also in the rulemaking docket.

[8] The EPA developed the memorandum to determine appropriate RDL and 3XRDL values for sorbent trap monitoring systems, as well as calculate an emissions limit, in order to determine the shortest, reasonable sample collection period for those systems. See EPA Docket ID EPA–HQ–OAR–2009–0234–20222.

all runs of an individual emissions test as the operating limit, provided that the result of the individual emissions test met the emissions limit. The third approach, which the EPA is finalizing in this final action, would require an EGU owner or operator to use the higher of the following: (1) A parameter scaled from all values obtained during an individual emissions test to 75 percent of the emissions limit or (2) the average parameter value obtained from all runs of an individual emissions test as the operating limit provided that the result of the individual emissions test met the emissions limit. As established and reaffirmed in the recent Sewage Sludge Incineration, Major Source Industrial Boiler, and Portland Cement rules,[9] it is appropriate to provide increased operational flexibility and reduced emissions testing for sources that emit at or below 75 percent of a standard—whether an emissions or operating limit—as these are the lowest emitting sources. Reduced emissions testing is available in this final rule for those owners or operators whose EGU emissions do not exceed this 75 percent threshold. This 75 percent threshold allows for compliance flexibility and is simultaneously protective of the emission standards. The EPA believes well performing EGUs, i.e., those whose emissions do not exceed 75 percent of the emissions limit, should not face additional scrutiny or testing consequences provided their emissions remain equivalent to or below the 75 percent threshold. In this final action, the EPA uses the 75 percent threshold so as not to impose unintended and costly retest requirements for the lowest emitting sources and to provide for more cost effective, continuous, PM parametric monitoring across the EGU sector. This approach was selected from the options considered as it provides the greatest amount of EGU owner or operator flexibility while demonstrating continuous compliance for EGUs. With this parametric monitoring approach in place, the EPA expects EGUs to evaluate control options that provide excellent fPM emissions control and provide them greater operational flexibility.

Moreover, after each exceedance of the operating limit, the EPA proposed to require emissions testing to verify or re-adjust the operating limit, consistent with the approach contained in the recently-promulgated Portland cement MACT standard (see 78 FR 10014). One commenter objected to potential frequent emissions testing to reassess the operating limit and then being subject to a violation of the emissions limit. The EPA does not believe that too-frequent testing will be required. As discussed in section 4.3.5 of the RTC, the EPA believes well-designed emissions testing will provide an operating limit corresponding with EGU operation, and such testing should yield an operating limit that would not be expected to be exceeded during the course of EGU operation. Therefore, an operating limit developed from well-designed emissions testing should have little, if any, need for frequent reassessment via emissions testing more frequently than the mandated annual reassessment because the source will be able to meet the limit on an ongoing basis.

Finally, the EPA proposed that PM CPMS exceedances leading to more than 4 required emissions tests in a 12-month period (rolling monthly) would be presumed (subject to the possibility of rebuttal by the EGU owner or operator) to be a violation of the emissions limit, consistent with the approach contained in the newly-promulgated Portland cement MACT standard (see 78 FR 10014). The EPA received a number of comments on this proposed provision, including comments supporting and opposing the establishment of such a presumption.

The EPA disagrees with those comments opposing the presumptive violation, and believes the presumptive violation provision in the final rule is a reasonable and appropriate approach to ensure compliance with the standard. First, the EPA may permissibly establish such an approach by rule, assuming there is a reasonable factual basis to do so. See *Hazardous Waste Treatment Council* v. *EPA,* 886 F. 2d 355, 367–68 (DC Cir. 1989) (explaining that such presumptions can legitimately establish the elements of the EPA's *prima facie* case in an enforcement action). Second, there is a reasonable basis here for the presumption that four exceedances (i.e., increases over the parametric operating limit) in a calendar year are a violation of the emission standard. The parametric monitoring limit is established as a 30-day average of the averaged test value in the performance test, or the 75th percentile value if that is higher. In either instance, the 30-day averaging feature provides significant leeway to the EGU owner or operator not to deviate from the parametric operating level because the impact of transient peaks or valleys is limited due to the length of the rule's averaging period—30 boiler operating days, rolled daily. See 77 FR 42377/2 and sources there cited. See also 78 FR 10015, 10019; February, 12, 2013 (Portland Cement MACT) and the RTC for today's action.

The EPA also received comments addressing the re-testing requirements following an exceedance. Some commenters expressed concern about the burden of requiring sources to conduct performance tests in order to demonstrate compliance and to reassess the parameter level. In contrast, other commenters supported a requirement to require re-testing but claimed that the time period between observing a parameter exceedance and retesting is too long. The EPA believes that the re-testing requirements are reasonable and appropriate to identify non-compliance without imposing undue burden. For even a single exceedance to occur, the 30-day average would have to be higher than the operating limit established for the PM CPMS during normal EGU operation. If that occurs, then the EGU owner or operator is required to conduct an inspection to determine any abnormalities and an emissions test to re-establish or generate a new operating limit. Given that EGUs and their emissions control devices are designed to operate at known, specific conditions, deviations from these conditions are not expected and are indicative of problems with load, controls, or some combination of both. Where these sorts of problems result in an exceedance of the source's operating limit, it is reasonable to require re-testing in order to identify and then correct problems. More than four such exceedances of the 30-day average would mean that the EGU owner or operator was unable to determine or correct the problem, since inspection and re-calculation of the operating limit is required after each exceedance. This indicates an ongoing problem with maintaining process control and/or control device operation, which would be the basis for a presumptive violation of the emissions standard. Moreover, the EPA disagrees that the period between exceedance of the operating limit and retesting is too long and could result in possible excessive emissions. Specifically, some commenters claimed that the final rule should not limit the number of exceedances of the PM CPMS limit that require follow-up performance tests in any 12-month period. These commenters alleged that to do so does

[9] See *Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units,* 76 FR 15736 (March 21, 2011); *Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters,* 40 CFR 63.7515(b); and *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10014 (February 12, 2013).

not ensure continuous compliance because the time period between an exceedance and testing could be too long, and a source could be exceeding the emission limit during that time period. The EPA believes that the re-testing requirements reflect a reasonable balance between ensuring compliance and limiting unnecessary testing burden on regulated sources. An EGU owner or operator is required to visually inspect the air pollution control device within 48 hours of the exceedance, and corrective action must be taken as soon as possible to return the PM CPMS measurement to within the established value. A performance test is also required within 45 days of the exceedance to determine compliance and verify or re-establish the PM CPMS limit. Thus, the EPA finds it unlikely that there will be long periods of noncompliance with the underlying fPM standard given the inspection and performance testing requirements.

The EPA also received comments stating that an EGU owner or operator should not be labeled a ''violator'' of the fPM standard as a result of a fourth compliance test in a 12-month period. First, the EPA notes that the rule identifies more than 4 compliance tests over a 12-month period as only a presumptive violation of the emissions limit. A presumption of a violation is just that—a presumption—and can be rebutted in any particular case.

Moreover, in determining whether the presumption has been successfully rebutted, a Court may consider relevant information such as data or other information showing that the EGU's operating process remained in control during the period of operating parameter exceedance, that the ongoing operation and maintenance conducted on the EGU ensured its emissions control devices remained in proper operating condition during the period of operating parameter exceedance, and that results of emissions tests conducted while replicating the conditions observed during the period of operating parameter exceedance remained below the emission limit.

For the reasons explained above, this final action includes the presumption of violation of the emissions limit if more than 4 emissions tests are required in a 12-month period.

V. Summary of Final Action and Changes Since Proposal—Utility NSPS

The EPA has made a number of changes from the reconsideration proposal in this final action after consideration of the public comments received. Most of the changes to the Utility NSPS clarify applicability and implementation issues raised by the commenters. The public comments received on the matters proposed for reconsideration and the responses to them can be viewed in the memorandum ''Summary of EGU NSPS Public Comments and Responses on Amendments Proposed November 30, 2012 (77 FR 71323)'' in rulemaking docket EPA–HQ–OAR–2011–0044.

In the proposed reconsideration rule, the EPA proposed a new definition for IGCC which would be consistent with the MATS NESHAP definition. However, as an alternative we requested comment on whether to retain a definition similar, but not identical, to the IGCC definition in the February 2012 final Utility NSPS. We have concluded that the alternative approach is most appropriate and are adopting a slightly revised definition that is consistent with the Agency's statements on IGCC contained in the RTC in support of the final Utility NSPS rule published on February 16, 2012 (77 FR 9304). Commenters generally supported amending the final Utility NSPS definition of IGCC, and this final action amends that definition consistent with the statements made in the RTC for the Utility NSPS. The Utility NSPS IGCC definition deals with the intent of an IGCC facility and is, thus, broader than the definition in the MATS NESHAP. The facility would still be subject to the same criteria pollutant emission standards even when burning natural gas for extended periods of time. The MATS NESHAP applicability is determined based on the EGU's utilization of coal and oil and the rule may not apply depending on the extent of natural gas usage.

The EPA proposed that the NSPS PM monitoring procedures be consistent with the MATS NESHAP requirements and included the use of quarterly stack testing, PM CPMS, or PM CEMS. In addition, the EPA sought comment on whether to include the quarterly stack testing compliance option for new EGUs, given that continuous, direct measurement of PM or a correlated parameter is available. EGUs complying with an output-based emissions standard can be designed to incorporate PM CEMS or PM CPMS from the outset, without being impeded by retrofit location installation constraints that would impact existing EGUs. This final action requires EGUs complying with an output-based standard to use either PM CEMS or PM CPMS as options for determining compliance with the PM limits. Therefore, the EPA is finalizing the same monitoring procedures for PM for the Utility NSPS as for new sources subject to the MATS NESHAP, and is not finalizing the quarterly stack testing option.

The EPA proposed that facilities using PM CPMS would be able to use either a continuous opacity monitoring system or a periodic alternate monitoring approach to monitor opacity. This final action does not require facilities using a PM CPMS to conduct opacity monitoring. The EPA has concluded that the use of a PM CPMS at the level of the emissions standard required in subpart Da is sufficient to demonstrate compliance with the opacity standard and that additional monitoring is an unnecessary burden.

VI. Technical Corrections and Clarifications

On April 19, 2012 (77 FR 23399), the EPA issued a technical corrections notice addressing certain corrections to the February 16, 2012 (77 FR 9304), MATS NESHAP and Utility NSPS. In the November 30, 2012, reconsideration proposal, we proposed several additional technical corrections. Specific to the NSPS, we proposed correcting the PM standard for facilities that commenced construction before March 1, 2005, to remove the extra significant digit that was inadvertently added and to correct the PM standard for facilities that commence modification after May 3, 2011, to be consistent with the original intent as expressed in the RTC of the final rule published on February 16, 2012 (77 FR 9304). We did not receive any negative comments on these issues and are finalizing them as proposed. Specific details are included in Table 3.

Specific to the MATS NESHAP, the EPA requested comment on whether the proposed technical corrections in Table 4 of the preamble provide the intended accuracy, clarity, and consistency. As mentioned in section 6.3 of the RTC, commenters supported the proposed changes on equations 2a and 3a and this final action contains those changes. As mentioned in section 6.3 of the RTC, commenters did not support the change from a 30 to 60-day notification period for performance testing, and that change was not made to the rule; however, a change to the General Provisions applicability table was made to provide a consistent 30-day notification period. Commenters suggested changes to certain definitions to make them more consistent with the Acid Rain rule provisions, but, as described in section 6.4 of the RTC, these rule changes were not made. These amendments are now being finalized to correct inaccuracies and other inadvertent errors in the final rule and to make the rule language

consistent with provisions addressed through this reconsideration.

The final technical changes are described in tables 3 and 4 of this preamble.

TABLE 3—MISCELLANEOUS TECHNICAL CORRECTIONS TO 40 CFR PART 60, SUBPART DA

Section of subpart Da	Description of correction
40 CFR 60.42Da(a)	Correct the erroneous "0.030" to the correct "0.03".
40 CFR 60.42Da(e)(1)(ii)	Correct the erroneous conversion "13 ng/J (0.015 lb/MMBtu)" to the correct "6.4 ng/J (0.015 lb/MMBtu)" by amending the regulatory text to specify that the requirements in 40 CFR 60.42Da(c) or (d), which includes two additional alternative limits, are available compliance alternatives for modified facilities.

TABLE 4—MISCELLANEOUS TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART UUUUU

Section of subpart UUUUU	Description of correction
40 CFR 63.9982(a)	Clarify the language to use the word "or" instead of "and."
40 CFR 63.9982(b) and (c)	Correct the discrepancy between 63.9982(b) and (c) and 63.9985(a).
40 CFR 63.10005(d)(2)(ii)	Correct the typographical error by replacing the incorrect "corresponding" with the correct "corresponds."
40 CFR 63.10005(i)(4)(ii) and (i)(5) and add 63.10005(i)(6).	Revise to clarify the determination and measurement of fuel moisture content.
40 CFR 63.10006(c)	Correct the omission of solid oil-derived fuel- and coal-fired EGUs and IGCC EGUs and the omission of section 10000(c).
40 CFR 63.10007(c)	Correct the omission of section 63.10023 from the list of sections to be followed in establishing an operating limit.
40 CFR 63.10009(b)(2)	Correct omission of the term "boiler operating" and clarify the term "Rt_i" in Equation 2a.
40 CFR 63.10009(b)(3)	Correct omission of the term "system" and clarify the term "Rt_i" in Equation 3a.
40 CFR 63.10010(j)(1)(i)	Correct the typographical error to use the correct word "your" instead of "you."
40 CFR 63.10030(b), (c), and (d)	Clarify the affected-source language.
	Change the period by which a Notification of Intent to conduct a performance test must be submitted to conform to the General Provisions.
40 CFR Section 63.10042	Correct the typographical error in the intended definition of "unit designed for coal ≥ 8,300 Btu/lb subcategory" by replacing the erroneous ">" with the correct "≥."
Table 5 to Subpart UUUUU of Part 63.	Correct the typographical error in footnote 4 by replacing the erroneous "≥" with the correct "≤."
Table 7 to Subpart UUUUU of Part 63.	Clarify the applicability of the alternate 90-day average for Hg in item 1.
	Revise item 3 in the table to clarify use of CMS for liquid oil-fired EGUs.
Table 9 to Subpart UUUUU of Part 63.	Revise to clarify the period for notification of conducting a performance test from 60 to 30 days.
Section 4.1 to Appendix A to Subpart UUUUU of Part 63.	Correct the typographical error by replacing the incorrect citation to "§ 63.10005(g)" with the correct "§ 63.9984(f)."
Section 5.2.2.2 to Appendix A to Subpart UUUUU of Part 63.	Correct the typographical error by replacing the incorrect citation to "Table A–4" with the correct "Table A–2"
Section 3.1.2.1.3 to Appendix B to Subpart UUUUU of Part 63.	Correct the typographical error by replacing the erroneous "≥" with the correct "≤."
Section 5.3.4 to Appendix B to Subpart UUUUU of Part 63.	Correct the section number from the incorrect "5.3.4" to the correct "5.3.3."

VII. Impacts of This Final Rule

A. Summary of Emissions Impacts, Costs and Benefits

Our analysis shows that new EGUs would choose to install and operate the same or similar air pollution control technologies in order to meet the revised emission limits as would have been necessary to meet the previously finalized standards. We project that this final action will result in no significant change in costs, emission reductions, or benefits.[10] Even if there were changes in costs for these EGUs, such changes would likely be small relative to both the overall costs of the individual projects and the overall costs and benefits of the final rule. Further, we believe that EGUs would put on the same controls for this final action that they would have for the original final MATS rule, so there should not be any incremental costs related to this revision.

B. What are the air impacts?

We believe that electric power companies will install the same or similar control technologies to comply with the final standards in this action as they would have installed to comply with the previously finalized MATS standards. Accordingly, we believe that this final action will not result in significant changes in emissions of any of the regulated pollutants.

C. What are the energy impacts?

This final action is not anticipated to have an effect on the supply, distribution, or use of energy. As previously stated, we believe that electric power companies would install the same or similar control technologies as they would have installed to comply with the previously finalized MATS standards.

D. What are the compliance costs?

We believe there will be no significant change in compliance costs as a result of this final action because electric

[10] See *Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards [EPA–452/R–11–011]* (docket entry EPA–HQ–OAR–2009–0234–20131) and *Economic Impact Analysis for the Final Reconsideration of the Mercury and Air Toxics Standards* in rulemaking docket EPA–HQ–OAR–2009–0234. As noted earlier, because on an individual EGU-by-EGU basis we anticipate very similar costs, any changes to the baseline since we finalized MATS (e.g., potential impacts of the CSAPR decision) would not impact this determination.

power companies would install the same or similar control technologies as they would have installed to comply with the previously finalized MATS standards. Moreover, we find no additional monitoring costs are necessary to comply with this final action; however, as in any other rule, EGU owners or operators may choose to conduct additional monitoring (and incur its expense) for their own purposes.

E. What are the economic and employment impacts?

Because we expect that electric power companies would install the same or similar control technologies to meet the standards finalized in this action as they would have chosen to comply with the previously finalized MATS standards, we do not anticipate that this final action will result in significant changes in emissions, energy impacts, costs, benefits, or economic impacts. Likewise, we believe this action will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy.

F. What are the benefits of the final standards?

As previously stated, the EPA anticipates the power sector will not incur significant compliance costs or savings as a result of this action and we do not anticipate any significant emission changes resulting from this action. Therefore, there are no direct monetized benefits or disbenefits associated with this action.

VIII. Statutory and Executive Order Reviews

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

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

In addition, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the ''Economic Impact Analysis for the Final Reconsideration of the Mercury and Air Toxics Standards'' found in rulemaking docket EPA–HQ–OAR–2009–0234. Because our analysis shows that new electricity generating units would choose to install the same control technology in order to meet the revised emission limits as would have been necessary to meet the previously finalized MATS standards, we project that this action will result in no significant change in costs, emission reductions, or benefits.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. Today's action does not change the information collection requirements previously finalized and, as a result, does not impose any additional burden on industry. However, OMB has previously approved the information collection requirements contained in the existing regulations (see 77 FR 9304) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0567. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

C. Regulatory Flexibility Act

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

For purposes of assessing the impacts of today's action on small entities, a small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less that 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. Categories and entities potentially regulated by the final rule with applicable NAICS codes are provided in the Supplementary Information section of this action.

According to the SBA size standards for NAICS code 221122 Utilities-Fossil Fuel Electric Power Generation, a firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million MWh.

After considering the economic impacts of today's action on small entities, I certify that the notice will not have a significant economic impact on a substantial number of small entities.

The EPA has determined that none of the small entities will experience a significant impact because the action imposes no additional regulatory requirements on owners or operators of affected sources. We have therefore concluded that today's action will not result in a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act

This action contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for State, local, or tribal governments or the private sector. The action imposes no enforceable duty on any State, local, or tribal governments or the private sector. Therefore, this action is not subject to the requirements of UMRA sections 202 or 205.

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

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. None of the affected facilities are owned or operated by state governments, and the requirements discussed in today's notice will not supersede state regulations that are more stringent. Thus, EO 13132 does not apply to today's notice of reconsideration.

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

This action does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in EO 13175. No affected

facilities are owned or operated by Indian tribal governments. Thus, EO 13175 does not apply to today's action.

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

This action is not subject to EO 13045 (62 FR 19885; April 23, 1997) because it is not economically significant as defined in EO 12866. The EPA has evaluated the environmental health or safety effects of the final MATS on children. The results of the evaluation are discussed in that final rule (77 FR 9304; February 16, 2012) and are contained in rulemaking docket EPA–HQ–OAR–2009–0234.

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

This action is not a "significant energy action" as defined in EO 13211 (66 FR 28355; May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we conclude that today's action is not likely to have any adverse energy effects because it is not expected to impose any additional regulatory requirements on the owners of affected facilities.

I. National Technology Transfer and Advancement Act

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

During the development of the final MATS rule, the EPA searched for voluntary consensus standards that might be applicable. The search identified three voluntary consensus standards that were considered practical alternatives to the specified EPA test methods. An assessment of these and other voluntary consensus standards is presented in the preamble to the final MATS rule (77 FR 9441; February 16, 2012). Today's action does not make use of any additional technical standards beyond those cited in the final MATS rule. Therefore, the EPA is not considering the use of any additional voluntary consensus standards for this action.

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

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

The EPA has determined that this action will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. Our analysis shows that new EGUs would choose to install the same control technology in order to meet the revised emission limits as would have been necessary to meet the previously finalized standard. Under the relevant assumptions, we project that this action will result in no significant change in emission reductions.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective April 24, 2013.

List of Subjects in 40 CFR Parts 60 and 63

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

Dated: March 28, 2013.

Bob Perciasepe,

Acting Administrator.

For the reasons discussed in the preamble, 40 CFR parts 60 and 63 are amended to read as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

■ 2. Amend § 60.41Da by revising the definitions of "Coal" and "Integrated gasification combined cycle electric utility steam generating unit," and by adding the definition of "Natural gas" in alphabetical order to read as follows:

§ 60.41Da Definitions.

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

* * * * *

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas

does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

* * * * *

■ 3. Amend § 60.42Da by revising paragraphs (a), (b)(2), and (e)(1) to read as follows:

§ 60.42Da Standards for particulate matter (PM).

(a) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain PM in excess of 13 ng/J (0.03 lb/MMBtu) heat input.

(b) * * *

(2) An owner or operator of an affected facility that combusts only natural gas and/or synthetic natural gas that chemically meets the definition of natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

* * * * *

(e) * * *

(1) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator shall not cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the applicable emissions limit specified in paragraphs (e)(1)(i) or (ii) of this section.

(i) For an affected facility which commenced construction or reconstruction:

(A) 11 ng/J (0.090 lb/MWh) gross energy output; or

(B) 12 ng/J (0.097 lb/MWh) net energy output.

* * * * *

(ii) For an affected facility which commenced modification, the emission limits specified in paragraphs (c) or (d) of this section.

* * * * *

■ 4. Amend § 60.48Da by revising paragraphs (f), (o) introductory text, (o)(1), (o)(2) introductory text, (o)(3) introductory text, (o)(3)(i), and (o)(4) introductory text to read as follows:

§ 60.48Da Compliance provisions.

* * * * *

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with the applicable daily average PM emissions limit is determined by calculating the arithmetic average of all hourly emission rates each boiler operating day, except for data obtained during startup, shutdown, or malfunction periods. Daily averages must be calculated for boiler operating days that have out-of-control periods totaling no more than 6 hours of unit operation during which the standard applies. For affected facilities for which construction or reconstruction commenced after May 3, 2011, that elect to demonstrate compliance using PM CEMS, compliance with the applicable PM emissions limit in § 60.42Da is determined on a 30-boiler operating day rolling average basis by calculating the arithmetic average of all hourly PM emission rates for the 30 successive boiler operating days, except for data obtained during periods of startup or shutdown.

* * * * *

(o) Compliance provisions for sources subject to § 60.42Da(c)(2), (d), or (e)(1)(ii). Except as provided for in paragraph (p) of this section, the owner or operator must demonstrate compliance with each applicable emissions limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in § 60.42Da by the applicable date specified in § 60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months following the date the previous performance test was required to be conducted. You must conduct each performance test according to the requirements in § 60.8 using the test methods and procedures in § 60.50Da. The owner or operator of an affected facility that has not operated for 60 consecutive calendar days prior to the date that the subsequent performance test would have been required had the unit been operating is not required to perform the subsequent performance test until 30 calendar days after the next boiler operating day. Requests for additional 30 day extensions shall be granted by the relevant air division or office director of the appropriate Regional Office of the U.S. EPA.

(2) You must monitor the performance of each electrostatic precipitator or fabric filter (baghouse) operated to comply with the applicable PM emissions limit in § 60.42Da using a continuous opacity monitoring system (COMS) according to the requirements in paragraphs (o)(2)(i) through (vi) unless you elect to comply with one of the alternatives provided in paragraphs (o)(3) and (o)(4) of this section, as applicable to your control device.

* * * * *

(3) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of an electrostatic precipitator (ESP) operated to comply with the applicable PM emissions limit in § 60.42Da using an ESP predictive model developed in accordance with the requirements in paragraphs (o)(3)(i) through (v) of this section.

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in § 60.42Da operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the wet scrubber must be maintained and operated.

* * * * *

(4) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of a fabric filter (baghouse) operated to comply with the applicable PM emissions limit in § 60.42Da by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

* * * * *

■ 5. Amend § 60.49Da by:

■ a. Revising paragraphs (a) introductory text;

■ b. Adding paragraph (a)(3)(iv); and

■ c. Revising paragraphs (a)(4), (b) introductory text, and (t).

The revised and added text reads as follows:

§ 60.49Da Emission monitoring.

(a) An owner or operator of an affected facility subject to the opacity standard in § 60.42Da must monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the applicable requirements in paragraphs (a)(1) through (4) of this section.

* * * * *

(3) * * *

(iv) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to

performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations must be similar, but not necessarily identical, to the requirements in paragraph (a)(3)(iii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS ''Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.'' This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

* * * * *

(4) An owner or operator of an affected facility that is subject to an opacity standard under § 60.42Da is not required to operate a COMS provided that affected facility meets the conditions in either paragraph (a)(4)(i) or (ii) of this section.

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

(ii) The owner or operator of the affected facility installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

* * * * *

(b) The owner or operator of an affected facility must install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, except where only gaseous and/or liquid fuels (excluding residual oil) where the potential SO_2 emissions rate of each fuel is 26 ng/J (0.060 lb/MMBtu) or less are combusted, as follows:

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limit under § 60.42Da must either install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section or install, calibrate, operate, and maintain a PM CPMS according to the requirements for new facilities specified in subpart UUUUU of part 63 of this chapter. An owner or operator of an affected facility demonstrating compliance with the input-based emissions limit in § 60.42Da may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

* * * * *

■ 6. Revise § 60.50Da(f) to read as follows:

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(f) The owner or operator of an electric utility combined cycle gas turbine that does not meet the definition of an IGCC must conduct performance tests for PM, SO_2, and NO_X using the procedures of Method 19 of appendix A–7 of this part. The SO_2 and NO_X emission rates calculations from the gas turbine used in Method 19 of appendix A–7 of this part are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

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

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

■ 8. In § 63.9982, revise paragraphs (a) introductory text, (b), and (c) to read as follows:

§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, or existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

* * * * *

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, and if you commence reconstruction after May 3, 2011.

* * * * *

■ 9. In § 63.10000, revise paragraphs (c)(1)(iv) and (c)(2)(ii) to read as follows:

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

* * * * *

(c) * * *

(1) * * *

(iv) If your coal-fired or solid oil derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

* * * * *

(c) * * *

(2) * * *

(ii) If your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly.

* * * * *

■ 10. Amend § 63.10005 by:

■ a. Revising paragraphs (d)(2)(ii), (i)(4)(ii) and (i)(5);

■ b. Adding paragraph (i)(6).

The revised and added text read as follows:

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

* * * * *

(d) * * *

(2) * * *

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponds to the results of the performance test

demonstrating compliance with the emission limit with which you choose to comply.

* * * * *

(i) * * *

(4) * * *

(ii) ASTM D4006–11, ''Standard Test Method for Water in Crude Oil by Distillation,'' including Annex A1 and Appendix A1.

* * * * *

(5) Use one of the following methods to obtain fuel moisture samples:

(i) ASTM D4177–95 (Reapproved 2010), ''Standard Practice for Automatic Sampling of Petroleum and Petroleum Products,'' including Annexes A1 through A6 and Appendices X1 and X2, or

(ii) ASTM D4057–06 (Reapproved 2011), ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products,'' including Annex A1.

(6) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in § 63.10000(c)(2)(iii) or

(ii) Use an HCl CEMS and/or HF CEMS.

* * * * *

■ 11. In § 63.10006, revise paragraph (c) to read as follows:

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

* * * * *

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, § 63.10007, and § 63.10000(c), except as otherwise provided in § 63.10021(d)(1).

* * * * *

■ 12. In § 63.10007, revise paragraph (c) to read as follows:

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

* * * * *

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

* * * * *

■ 13. In § 63.10009, revise paragraphs (b)(2) and (b)(3) to read as follows:

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

* * * * *

(b) * * *

(2) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30 day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.2a)$$

Where:

Her_i = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Total heat input or gross electrical output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.2b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the ''coal-fired unit not low rank virgin coal'' subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.3a)$$

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Total heat input or gross electrical output of unit i for the preceding 90-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.3b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

* * * * *

■ 14. In § 63.10010, revise paragraph (j)(1)(i) to read as follows:

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

* * * * *

(j) * * *

(1) * * *

(i) Install and certify your HAP metals CEMS according to the procedures and requirements in your approved site-specific test plan as required in § 63.7(e). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (*e.g.,* lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

* * * * *

■ 15. Amend § 63.10021 by adding paragraphs (c)(1) and (2) to read as follows:

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

* * * * *

(c) * * *

(1) For any exceedance of the 30-boiler operating day PM CPMS average value from the established operating parameter limit for an EGU subject to the emissions limits in Table 1 to this subpart, you must:

(i) Within 48 hours of the exceedance, visually inspect the air pollution control device (APCD);

(ii) If the inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible, and return the PM CPMS measurement to within the established value; and

(iii) Within 45 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct any additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(2) PM CPMS exceedances of the operating limit for an EGU subject to the emissions limits in Table 1 of this subpart leading to more than four required performance tests in a 12-month period (rolling monthly) constitute a separate violation of this subpart.

* * * * *

■ 16. In § 63.10023, revise paragraph (b) to read as follows:

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

* * * * *

(b) Determine your operating limit as provided in paragraph (b)(1) or (b)(2) of this section. You must verify an existing or establish a new operating limit after each repeated performance test.

(1) For an existing EGU, determine your operating limit based on the highest 1-hour average PM CPMS output value recorded during the performance test.

(2) For a new EGU, determine your operating limit as follows.

(i) If your PM performance test demonstrates your PM emissions do not exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. Calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in (b)(2)(i)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

(*1*) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*2*) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*3*) The zero point can also can be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*4*) If none of the steps in paragraphs (A)(*1*) through (*3*) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average (*x*) in milliamps, and the average of your corresponding three PM compliance test runs (*y*), using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_i, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_i \qquad \text{(Eq. 10)}$$

Where:

X_i = the PM CPMS data points for run i of the performance test,

Y_i = the PM emissions value (in lb/MWh) for run i of the performance test, and

n = the number of data points.

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11.

$$R = \frac{\bar{y}}{(\bar{x} - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative PM lb/MWh per milliamp for your PM CPMS,

$\bar{y}$ = the three run average PM lb/MWh,

$\bar{x}$ = the three run average milliamp output from your PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_L = z + \frac{(0.75 \times L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_L = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,

L = your source PM emissions limit in lb/MWh,

z = your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and

R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit.

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_i \qquad \text{(Eq. 13)}$$

Where:

X_i = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(iii) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

* * * * *

■ 17. In § 63.10030, revise paragraphs (b), (c), and (d) to read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(b) As specified in § 63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed EGU that is an affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the EGU that is an affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

* * * * *

■ 18. Amend § 63.10042 by revising the definition of ''Unit designed for coal > 8,300 Btu/lb subcategory'' to read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Unit designed for coal ≥ 8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the ''unit designed for low rank virgin coal'' subcategory.

* * * * *

■ 19. Revise Table 1 to Subpart UUUUU of Part 63 to read as follows:

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS

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

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E–2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh[4] 9.0E–2 lb/MWh[5]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E–2 lb/GWh.	
	Arsenic (As)	2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	4.0E–2 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

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

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Cobalt (Co)	4.0E–3 lb/GWh.	
	Lead (Pb)	9.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	
	Lead (Pb)	3.0E–2 lb/GWh.	
	Manganese (Mn)	1.0E–1 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

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

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Nickel (Ni)	4.1E0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	5.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	3.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross electric output.
[2] Incorporated by reference, see § 63.14.
[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.
[4] Duct burners on syngas; gross electric output.
[5] Duct burners on natural gas; gross electric output.

■ 20. Revise Table 4 to Subpart UUUUU of Part 63 to read as follows:

TABLE 4 TO SUBPART UUUUU OF PART 63—OPERATING LIMITS FOR EGUS

[As stated in §§ 63.9991, you must comply with the applicable operating limits]

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. PM CPMS for an existing EGU ..	Maintain the 30-boiler operating day rolling average PM CPMS output at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).
2. PM CPMS for a new EGU	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

■ 21. Revise footnote 4 of Table 5 to Subpart UUUUU of Part 63 to read as follows:

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS

* * * * * * *

[4] When using ASTM D6348–03, the following conditions must be met: (1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; (2) For ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%)R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≤ R ≤ 130%; and (4) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

■ 22. Revise Table 6 to Subpart UUUUU of Part 63 to read as follows:

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
1. Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an existing EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the three run performance test. 3. Determine the highest 1-hour average PM CPMS measured during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS—Continued

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
2. Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for a new EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

■ 23. Revise Table 7 to Subpart UUUUU of Part 63 to read as follows:

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

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

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

■ 24. Revise Table 9 to Subpart UUUUU of Part 63 to read as follows:

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention.	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c), (f)(2)–(3), (g), (h)(2)–(h)(9), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions.	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP.	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.7(a), (b), (c), (d), (e)(2)–(e)(9), (f), (g), and (h).	Performance Testing Requirements.	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS.	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification requirements	Yes, except for the 60-day notification prior to conducting a performance test in § 63.9(d); instead use a 30-day notification period per § 63.10030(d).
§ 63.10(a), (b)(1), (c), (d)(1)–(2), (e), and (f).	Recordkeeping and Reporting Requirements.	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions.	Yes.
§ 63.10(b)(2)(vii)–(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3),and (d)(3)–(5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions.	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3)–(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9).	Reserved	No.

■ 25. Revise sections 4.1 and 5.2.2.2 to Appendix A to Subpart UUUUU of Part 63 to read as follows:

Appendix A to Subpart UUUUU—Hg Monitoring Provisions

* * * * *

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in § 63.9984(f).

* * * * *

5.2.2.2 The same RATA performance criteria specified in Table A–2 for Hg CEMS also apply to the annual RATAs of the sorbent trap monitoring system.

* * * * *

■ 26. Revise section 3.1.2.1.3 and the heading to section 5.3.4 to Appendix B to Subpart UUUUU of Part 63 to read as follows:

Appendix B to Subpart UUUUU—HCl and HF Monitoring Provisions

* * * * *

3.1.2.1.3 For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≤ R ≤ 130%; and

* * * * *

5.3.3 *Conditional Data Validation*

* * *

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BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2012–0282; FRL–9384–2]

Azoxystrobin; Pesticide Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes tolerances for residues of azoxystrobin in or on multiple commodities discussed later in this document. Syngenta Crop Protection, LLC requested these tolerances under the Federal Food, Drug, and Cosmetic Act (FFDCA).

DATES: This regulation is effective April 24, 2013. Objections and requests for hearings must be received on or before June 24, 2013, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for these actions, identified by docket identification (ID) number EPA–HQ–OPP–2012–0282, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), EPA West Bldg., Rm. 3334, 1301 Constitution Ave. NW., Washington, DC 20460–0001. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Erin Malone, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; telephone number: (703) 347–0253; email address: *Malone.Erin@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of EPA's tolerance regulations at 40 CFR part 180 through the Government Printing Office's eCFR site at *http://www.ecfr.gov/cgi-bin/text-idx?&c=ecfr&tpl=/ecfrbrowse/Title40/40tab_02.tpl.*

C. How can I file an objection or hearing request?

Under FFDCA section 408(g), 21 U.S.C. 346a, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2012–0282 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing, and must be received by the Hearing Clerk on or before June 24, 2013. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA–HQ–OPP–2012–0282, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.
- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001.
- *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.htm.*

Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets.*

II. Summary of Petitioned-For Tolerance

In the **Federal Register** of April 4, 2012 (77 FR 20336) (FRL–9340–4), EPA issued a document pursuant to FFDCA section 408(d)(3), 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide petition (PP 1E7945) by Syngenta Crop Protection, LLC, P.O. Box 18300, Greensboro, NC 27419–8300. The petition requested that 40 CFR 180.507 be amended by establishing an import tolerance for residues of the fungicide azoxystrobin, [methyl(E)-2-(2-(6-(2-cyanophenoxy) pyrimidin-4-yloxy)phenyl)-3-methoxyacrylate], and the *Z*-isomer of azoxystrobin, [methyl(*Z*)-2-(2-(6-(2-