FEDERAL REGISTER

Vol. 79 Friday,
No. 65 April 4, 2014

Part II

Environmental Protection Agency

40 CFR Part 60
Kraft Pulp Mills NSPS Review; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2012–0640; FRL–9907–37–OAR]

RIN 2060–AR64

Kraft Pulp Mills NSPS Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes revisions to the new source performance standards for kraft pulp mills. These revised standards include particulate matter emission limits for recovery furnaces, smelt dissolving tanks and lime kilns, and opacity limits for recovery furnaces and lime kilns equipped with electrostatic precipitators. These revised standards apply to emission units commencing construction, reconstruction or modification after May 23, 2013. This final rule removes the General Provisions exemption for periods of startup, shutdown and malfunction resulting in a standard that applies at all times. This final rule also includes additional testing requirements and updated monitoring, recordkeeping and reporting requirements for affected sources, including electronic reporting of performance test data. These revisions to the testing, monitoring, recordkeeping and reporting requirements are expected to ensure that control systems are properly maintained over time, ensure continuous compliance with standards and improve data accessibility for the Environmental Protection Agency (EPA), states, tribal governments and communities.

DATES: This final action is effective on April 4, 2014. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of April 4, 2014.

ADDRESSES: The EPA has established a docket for this action under Docket ID Number EPA–HQ–OAR–2012–0640. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available (e.g., confidential business information or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, 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, Public Reading Room, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final rule for kraft pulp mills, contact Dr. Kelley Spence, Natural Resources Group, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (E143–03), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541–3158; fax number (919) 541–3470; email address: *spence.kelley@epa.gov*.

SUPPLEMENTARY INFORMATION:

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

ADTP Air dried ton of pulp
Agency U.S. Environmental Protection Agency
ANSI American National Standards Institute
ASME American Society of Mechanical Engineers
BDT Best demonstrated technology
BLO Black liquor oxidation
BLS Black liquor solids
BSER Best system of emissions reduction
BSW Brown stock washer
CAA Clean Air Act
CBI Confidential business information
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS Continuous emission monitoring system
CFR Code of Federal Regulations
Cir. Circuit Court
COMS Continuous opacity monitoring system
Court United States Court of Appeals for the District of Columbia Circuit
CWA Clean Water Act
D.C. Cir. United States Court of Appeals for the District of Columbia Circuit
dscf Dry standard cubic foot
EPA U.S. Environmental Protection Agency
ERT Electronic Reporting Tool
ESP Electrostatic precipitator
FR **Federal Register**
gr Grain(s)
H_2S Hydrogen sulfide
HAP Hazardous air pollutant(s)
HVLC High-volume, low-concentration
IBR Incorporation by Reference
ICR Information collection request
lb Pound(s)
LVHC Low-volume, high-concentration
N/A Not applicable
NAICS North American Industry Classification System
NESHAP National emission standards for hazardous air pollutants
NSPS New source performance standards
NTTAA National Technology Transfer and Advancement Act of 1995
NW Northwest
O&M Operating and maintenance
O_2 Oxygen
OMB Office of Management and Budget
PM Particulate matter
ppm Parts per million
ppmdv Part(s) per million by dry volume
PTC Performance Test Code
RTR Risk and technology review
SDT Smelt dissolving tank
SSM Startup, shutdown and malfunction
TAPPI Technical Association of the Pulp and Paper Industry
TRS Total reduced sulfur
TTN Technology Transfer Network
U.S. United States
U.S.C. United States Code
UMRA Unfunded Mandates Reform Act
v. Versus
VCS Voluntary consensus standard(s)
VOC Volatile organic compound
yr Year(s)

Background Information Document. On May 23, 2013, the EPA proposed revisions to the Kraft Pulp Mills New Source Performance Standards (NSPS) based on evaluations performed by the EPA to conduct the NSPS review. In this action, we are finalizing revisions to the rule. A document summarizing the public comments on the proposal and presenting the EPA responses to those comments is available in Docket ID Number EPA–HQ–OAR–2012–0640.

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

A red-line version of the regulatory language that incorporates the changes in this action is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2012–0640).

I. Executive Summary

A. Purpose of Regulatory Action

Section 111(b)(1)(B) of the Clean Air Act (CAA) requires the EPA to review and, if appropriate, revise existing NSPS at least every 8 years. The NSPS for Kraft Pulp Mills (40 CFR part 60, subpart BB) were promulgated in 1978 and last reviewed in 1986. In this review, the EPA considers what degree of emission limitation is achievable through the application of the best system of emission reductions (BSER), which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. The EPA also considers the emission limitations and reductions that have been achieved in practice.

In addition to conducting the NSPS review, the EPA evaluated the startup, shutdown and malfunction (SSM) provisions in this rule in light of the District of Columbia Circuit Court of Appeals (D.C. Cir.) decision in *Sierra Club* v. *EPA*, 551 F.3d 1019 (D.C. Cir. 2008), which held that the SSM exemption in the General Provisions in 40 CFR part 63 violated the CAA's requirement that some standard apply continuously. In the *Sierra Club* case, the D.C. Circuit vacated the SSM exemption provisions in the General Provisions of 40 CFR part 63 for non-opacity and opacity standards. The Court explained that under section 302(k) of the CAA, emission standards or limitations must be continuous in nature. The Court then held that the SSM exemption violates the CAA's requirement that some section 112 standard apply continuously. In light of the Court's reasoning, all rule provisions must be carefully examined to determine whether they provide for periods when no emission standard applies.

The EPA believes that even though the Court in *Sierra Club* v. *EPA* was considering a challenge to a section 112 national emissions standard for hazardous air pollutants (NESHAP), the Court's reasoning applies equally to CAA section 111 (NSPS) and section 129 rules. The EPA's general approach to SSM periods has been used consistently in promulgating new NSPS standards under CAA section 111, and in section 112 and section 129 rulemaking actions, since the DC Circuit's decision in *Sierra Club*. See, e.g., *New Source Performance Standards Review for Nitric Acid Plants, Final Rule*, 77 FR 48433 (August 14, 2012); *New Source Performance Standards for New Stationary Sources and Emission Guidelines for Existing Sources; Commercial and Industrial Solid Waste Incineration Units, Final rule*, 76 FR 15704, (March 21, 2011); *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final rules*, 77 FR 49490, (August 16, 2012).

To address the NSPS review, SSM exemptions and other changes, the EPA is promulgating new standards which apply to affected sources at kraft pulp mills for which construction, modification or reconstruction commences after May 23, 2013. The affected sources under the NSPS are new, modified or reconstructed digester systems, brown stock washer (BSW) systems, evaporator systems, condensate stripper systems, recovery furnaces, smelt dissolving tanks (SDTs) and lime kilns at kraft pulp mills. The requirements for these new, modified or reconstructed sources are included in a new subpart—40 CFR part 60, subpart BBa. The EPA is also promulgating testing, monitoring, recordkeeping and reporting requirements for subpart BBa that are in some ways different from what is required under 40 CFR part 60, subpart BB. Subpart BB continues to apply for affected sources that are constructed, modified or reconstructed after September 24, 1976, and on or before May 23, 2013, while subpart BBa applies for affected sources constructed, modified or reconstructed after May 23, 2013.

B. Summary of Major Provisions

Based on the results of the NSPS review, and following consideration of public comments, the EPA is finalizing the proposed 40 CFR part 60, subpart BBa standards for filterable particulate matter (PM), opacity and total reduced sulfur (TRS) compounds and is finalizing the associated proposed monitoring allowances. The final rule specifies that TRS emissions from digester systems, BSW systems, evaporator systems and condensate stripper systems that are controlled by incineration or other means must be collected in a low-volume high-concentration (LVHC) or a high-volume low-concentration (HVLC) closed-vent system meeting the requirements of the provisions of 40 CFR 63.450 of subpart S. Table 1 summarizes the final standards for filterable PM, opacity and TRS contained in subpart BBa.

TABLE 1—SUMMARY OF SUBPART BBa STANDARDS FOR AFFECTED SOURCES AT KRAFT PULP MILLS CONSTRUCTED, MODIFIED OR RECONSTRUCTED AFTER MAY 23, 2013

Affected sources	40 CFR 60.282a Filterable particulate matter (PM)	40 CFR 60.283a Total reduced sulfur (TRS)
Digester system, brown stock washer system, evaporator system and condensate stripper system.	None	Meet a limit of 5 ppmdv & 10% oxygen (O_2), unless one of the following conditions is met: 1. Collect emissions from affected source in LVHC or HVLC closed-vent system meeting the requirements in 40 CFR part 63, subpart S and combust in one of the following: (a) Lime kiln subject to subpart BB or BBa (8 ppmdv TRS & 10% O_2 limit); or

TABLE 1—SUMMARY OF SUBPART BBa STANDARDS FOR AFFECTED SOURCES AT KRAFT PULP MILLS CONSTRUCTED, MODIFIED OR RECONSTRUCTED AFTER MAY 23, 2013—Continued

Affected sources	40 CFR 60.282a Filterable particulate matter (PM)	40 CFR 60.283a Total reduced sulfur (TRS)
		(b) Recovery furnace subject to subpart BB or BBa (5 or 25 ppmdv TRS @ 8% O_2 limit); or (c) Incinerator, recovery furnace or lime kiln not subject to subpart BB or BBa, operated at a minimum temperature of 1,200 °F for 0.5 seconds (no ppmdv limit). 2. Collect emissions from affected source in LVHC or HVLC closed-vent system meeting the requirements in subpart S and use non-combustion control device with a limit of 5 ppmdv, uncorrected for O_2. 3. It is technologically or economically infeasible to incinerate BSW system gases. 4. Uncontrolled digester gases contain <0.01 pounds of TRS per air dried ton of pulp (lb TRS/ADTP).
Recovery furnace	1a. *Modified:* 0.044 grains per dry standard cubic foot (gr/dscf) @ 8% O_2; or 1b. *New/reconstructed:* 0.015 gr/dscf @ 8% O_2 and. 2. *ESP only:* 20% opacity; and 2% monitoring allowance for opacity (provided ESP secondary voltage/current or power exceed minimum operating limits).	1a. *Straight recovery furnace*[1] 5 ppmdv @ 8% O_2; and 1% monitoring allowance for TRS (restricted to ≤30 ppmdv @ 8% O_2 or 1b. *Cross recovery furnance*[2] 25 ppmdv @ 8% O_2 and 1% monitoring allownace for TRS (restricted to ≤50 ppmdv @ 8% O_2).
Smelt dissolving tank	1a. *Modified:* 0.2 lb/ton black liquor solids (BLS) dry weight; or 1b. *New/reconstructed:* 0.12 lb/ton BLS dry weight if associated with a new or reconstructed recovery furnace; or 1c. *New/reconstructed:* 0.2 lb/ton BLS dry weight if not associated with a new or reconstructed recovery furnace.	0.033 lb/ton BLS as hydrogen sulfide (H_2S).
Lime kiln	1a. *Modified:* 0.064 gr/dscf @ 10% O_2; or 1b. *New/reconstructed:* 0.010 gr/dscf @ 10% O_2; and 2.a *ESP only:* 20% opacity; and 1% monitoring allowance for opacity (provided ESP secondary voltage/current or power exceed minimum operating limits).	8 ppmdv & 10% O_2; and 1% monitoring allowance for TRS (restricted to ≤22 ppmdv & 10% O_2).

[1] A straight recovery furnace is one that only burns kraft pulping liquors.
[2] A cross recovery furnace is one that burns kraft and neutral sulfite semichemical pulping liquors.

Continuous monitoring of opacity is required for recovery furnaces and lime kilns that are not using wet scrubbers or combined electrostatic precipitator (ESP)/scrubber systems. Continuous monitoring of TRS emissions is required for recovery furnaces, lime kilns and other affected sources that comply with the TRS concentration limits. Parameter monitoring is required for ESPs, wet scrubbers and combined ESP/scrubber systems.

The emission standards are applicable at all times as specified in the monitoring and testing provisions in subpart BBa. The EPA is including in this final rule an affirmative defense to civil penalties for exceedances of emission limits caused by malfunctions that meet certain criteria (i.e., the exceedance must come from an "unavoidable failure"), along with recordkeeping and reporting requirements.

Initial and repeat performance testing is required once every 5 years for filterable PM and TRS for new, modified and reconstructed affected sources in subpart BBa. The EPA is also requiring initial and repeat performance testing for condensable PM to gather emissions data that will enable a broader understanding of condensable PM emissions from pulp and paper combustion sources. Mills must submit electronic copies of their performance test reports using the EPA's Electronic Reporting Tool (ERT). The EPA is also making certain technical and editorial changes, clarifying the location of applicable test methods in the Code of Federal Regulations (CFR), incorporating by reference two non-EPA test methods, and adding definitions pertinent to the requirements in subpart BBa.

C. Summary of Costs and Benefits

Table 2 summarizes the total costs for all sources subject to this action and the total benefits of this action. See section VI of this preamble for further discussion.

TABLE 2—SUMMARY OF THE COSTS AND BENEFITS OF SUBPART BBA FOR NEW, MODIFIED AND RECONSTRUCTED AFFECTED SOURCES AT KRAFT PULP MILLS.

Requirement	Capital cost ($ thousand)	Annual cost ($ thousand)	Net benefit
Repeat emissions testing	$186	$45	N/A
Monitoring	341	129	N/A
Incremental reporting/recordkeeping	50	215	N/A
Total nationwide	577	390	N/A

Note: Totals may not sum exactly due to rounding.

II. General Information

A. Does this action apply to me?

Categories and entities potentially regulated by this action include:

Category	NAICS [1] Code	Examples of regulated entities
Industry	3221	Kraft pulp mills.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility would be regulated by this action, you should examine the applicability criteria in 40 CFR 60.280a. If you have any questions regarding the applicability of this action to a particular entity, contact the person in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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

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

C. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by June 3, 2014. 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 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, William Jefferson Clinton 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.

III. Background

New source performance standards implement CAA section 111, which requires that each NSPS reflect the degree of emission limitation achievable through the application of the BSER which (taking into consideration the cost of achieving such emission reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is referred to as BSER and has been referred to in the past as "best demonstrated technology" or BDT. In assessing whether a standard is achievable, the EPA must account for routine operating variability associated with performance of the system on whose performance the standard is based. See *National Lime Ass'n* v. *EPA,* 627 F. 2d 416, 431–33 (D.C. Cir. 1980). In addition to new sources, existing affected sources that are modified or reconstructed are also subject to this final rule.

Section 111(b)(1)(B) of the CAA requires the EPA to periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions. The original NSPS for Kraft Pulp Mills (40 CFR part 60, subpart BB) were promulgated in the **Federal Register** on February 23, 1978 (43 FR 7572). The first review of the kraft pulp mills NSPS was completed on May 20, 1986 (51 FR 18544). The latest review of the Kraft Pulp Mills NSPS was proposed on May 23, 2013, under 40 CFR part 60, subpart BBa for emission units commencing construction, reconstruction or

modification after that date. This action finalizes this latest review, conducted pursuant to CAA section 111(b)(1)(B).

IV. Summary of the Final NSPS Review

A. What are the final rule requirements for kraft pulp mills?

1. Emission Limits

The NSPS for Kraft Pulp Mills (40 CFR 60, subpart BB) applies for digester systems, BSW systems, multiple-effect evaporator systems, condensate stripper systems, recovery furnaces, SDTs and lime kilns for which construction, modification or reconstruction commenced after September 24, 1976, and on or before May 23, 2013. Through this final NSPS review, the EPA is promulgating a new 40 CFR part 60, subpart BBa containing emission limits for affected sources constructed, modified or reconstructed after May 23, 2013. In this final rule (40 CFR 60, subpart BBa), the EPA is:

- Reducing the NSPS filterable PM limit for new and reconstructed recovery furnaces from 0.044 gr/dscf (in subpart BB) to 0.015 gr/dscf.
- Maintaining the current NSPS filterable PM limit of 0.044 gr/dscf for modified recovery furnaces.
- Reducing the NSPS opacity limit for recovery furnaces from 35-percent (in subpart BB) to 20-percent opacity, clarifying that the opacity limit does not apply where an ESP is used in combination with a wet scrubber, and reducing the monitoring allowance from 6 percent (in subpart BB) to 2 percent of the 6-minute opacity averages.
- Reducing the NSPS filterable PM limit for lime kilns from 0.066 gr/dscf for gas-fired kilns and 0.13 gr/dscf for liquid-fired kilns (in subpart BB) to 0.064 gr/dscf for modified lime kilns (all fuel types) and 0.010 gr/dscf for new or reconstructed lime kilns (all fuel types).
- Adding a 20-percent opacity limit for lime kilns equipped with ESPs with a 1-percent monitoring allowance and clarifying that the limit does not apply where an ESP is used in combination with a wet scrubber.
- Reducing the NSPS filterable PM limit for new and reconstructed SDTs associated with new or reconstructed recovery furnaces from 0.2 lb/ton BLS (in subpart BB) to 0.12 lb/ton BLS.
- Maintaining the current NSPS filterable PM limit of 0.2 lb/ton BLS for modified and new and reconstructed SDTs not associated with a new or reconstructed recovery furnace.
- Maintaining the current NSPS TRS limit for straight recovery furnaces at 5 parts per million by dry volume (ppmdv) and restricting the 1-percent monitoring allowance for TRS emissions to 30 ppmdv or less. Previously, there was no maximum TRS limit for these periods in subpart BB.
- Maintaining the current NSPS TRS limit for cross recovery furnaces at 25 ppmdv and adding a 1-percent monitoring allowance for TRS emissions restricted to 50 ppmdv. Previously, there was no maximum TRS limit for these periods in subpart BB.
- Maintaining the current NSPS TRS standards for digester systems, BSW systems, evaporator systems and condensate stripper systems.
- Specifying that sources which comply with the subpart BBa TRS standards for digester systems, BSW systems, evaporator systems and condensate stripper systems by venting to a combustion device such as a lime kiln, recovery furnace, incinerator, or other device (e.g., a boiler) or a non-combustion device must collect gases in an LVHC or HVLC closed-vent system meeting the provisions of 40 CFR 63.450 of subpart S.
- Maintaining the current NSPS TRS limit for lime kilns at 8 ppmdv and adding a 1-percent monitoring allowance restricted to 22 ppmdv.
- Maintaining the current NSPS TRS limit for SDTs at 0.033 lb/ton BLS.

The PM concentration emission limits are in terms of filterable PM measured by EPA Method 5. The TRS emission limits are in terms of TRS (or TRS as H_2S for SDTs) measured by EPA Method 16, 16A, 16B or 16C. Continuous monitoring of opacity is required for recovery furnaces and lime kilns that are not using wet scrubbers. Continuous monitoring of TRS emissions is required for recovery furnaces, lime kilns and other affected sources that comply with TRS concentration limits. This final rule states that the filterable PM and TRS standards apply at all times as specified in the monitoring and testing provisions in subpart BBa.

2. Parameter Monitoring Requirements

The EPA reviewed the subpart BB parameter monitoring requirements and is making several changes within subpart BBa. First, the EPA is promulgating ESP parameter monitoring requirements for recovery furnaces and lime kilns equipped with ESPs to enable affected units to show continuous compliance with the filterable PM concentration standards at all times, including periods when the opacity monitoring allowance is used. The EPA is requiring that these sources monitor the secondary voltage and secondary current (or, alternatively, total secondary power) of each ESP collection field. These ESP parameter monitoring requirements are in addition to opacity monitoring for recovery furnaces and lime kilns equipped with ESPs alone.

Second, the EPA is requiring wet scrubber parameter monitoring for recovery furnaces, SDTs and lime kilns equipped with wet scrubber systems (including combined ESP/scrubber systems). The parameter monitors will measure the wet scrubber pressure drop and scrubbing liquid flow rate (or scrubbing liquid supply pressure). Scrubber fan amperage monitoring is included in this final rule as an alternative to scrubber pressure drop monitoring for certain types of scrubbers used on SDTs (e.g., dynamic scrubbers that operate near atmospheric pressure).

Third, for recovery furnaces and lime kilns equipped with an ESP in combination with a wet scrubber system, the EPA is requiring ESP and wet scrubber parameter monitoring in place of opacity monitoring.

Also, subpart BBa specifies that parameters must be measured and recorded at least once every 15 minutes and reduced to 12-hour block averages, with two exceptions. When an opacity monitor is also used, the ESP parameters must be reduced to a semiannual average for use in the opacity monitoring allowance determination. The EPA is specifying a 5-minute data recording frequency and 3-hour block averaging time for incinerator temperature measurements required under subpart BBa.

3. Testing Requirements

As part of an ongoing effort to improve compliance with federal air emission regulations, the EPA reviewed the current filterable PM and TRS testing requirements of subpart BB and is including testing requirements for subpart BBa that are different from subpart BB in the following ways. First, although there is no emission limit for condensable PM in subpart BBa, the EPA is adding condensable PM to the list of pollutants to test to gather data to develop a broader understanding of condensable PM emissions from pulp and paper combustion sources. Second, the EPA is requiring repeat air emissions performance testing once every 5 years for facilities subject to NSPS subpart BBa. This final rule requires repeat air emissions testing for filterable PM, condensable PM and TRS once every 5 years for recovery furnaces, SDTs and lime kilns. Third, the EPA is including Method 16C as another alternative to Method 16 for measuring emissions of TRS from sources subject to the TRS standards in subpart BBa. Method 16C was not available at the time of the original NSPS and 1986 NSPS review. The method was

promulgated on July 30, 2012 (77 FR 44488). Fourth, the EPA is updating the method used to determine whether a kraft recovery furnace is a straight or cross recovery furnace to refer to the latest TAPPI Method T624 cm-11.

As in subpart BB, emission testing for subpart BBa is to be performed under representative operating conditions. Section 60.8(c) of the NSPS General Provisions is replaced in 40 CFR 60.285a(a) with a similar paragraph that states that testing is to be conducted under representative conditions and not during periods of startup, shutdown or malfunction.

4. Reporting and Recordkeeping Requirements

The existing subpart BB requires mills to keep records of TRS and opacity monitoring data along with scrubber and incinerator operating parameter data. The reporting requirements in the existing subpart BB include semiannual reports of performance tests and excess emissions as specified in 40 CFR 60.7(c).

Reporting and recordkeeping requirements are being included as separate sections within subpart BBa. Under this final rule, owners/operators subject to subpart BBa are required to keep records of all TRS and opacity monitoring data; all scrubber, incinerator and ESP operating parameter data; excess emissions; and malfunctions. A facility is required to report all exceedances of the standard, including exceedances that are the result of a malfunction. The malfunction recordkeeping requirements will provide pulp and paper companies with some of the information required to support the assertion of an affirmative defense in the event of a violation due to malfunction. In addition to the recordkeeping requirements specified in subpart BBa, 40 CFR 60.7(b) of the General Provisions requires records of the occurrence and duration of SSM events.

Under this final rule, owners/operators are required to report all performance test results (including electronic copies, as specified in section IV.D below) and excess emissions. Sections 60.7(c)(2) and 60.7(d) of the General Provisions require identification of periods of excess emissions that occur during SSM events. The frequency of reporting under subpart BBa is semiannually, the same as for subpart BB, and consistent with NESHAP requirements. Further, we are including a malfunction report to provide information on each type of malfunction which occurred during the reporting period and which caused or may have caused an exceedance of an emission limit.

5. Other Miscellaneous Differences Between Subpart BBa and Subpart BB

The following lists additional, minor differences between the current subpart BB NSPS and the subpart BBa final rule. This list includes rule differences that address editorial and other corrections. The EPA:

- Revised 40 CFR 60.17 to incorporate by reference ANSI/ASME PTC 19.10–1981 and TAPPI T624 cm-11 for subpart BBa.
- Revised the definitions section in 40 CFR 60.281a to alphabetize definitions; remove paragraph numbers; remove the definition for black liquor oxidation (BLO) system; add definitions for affirmative defense, closed-vent system, condensable PM, filterable PM, HVLC closed-vent system, LVHC closed-vent system and monitoring system malfunction; and revise the definition for digester system to include chip bins using live steam.
- Revised the wording of the PM standard in 40 CFR 60.282a and 40 CFR 60.285a to clarify that the PM emission limits in 40 CFR 60.282a and the Method 5 PM emission test in 40 CFR 60.285a refer to filterable PM, to avoid confusion with the inclusion of Method 202 condensable PM testing.
- Revised the wording of the TRS standard in 40 CFR 60.283a(a)(1) to clarify that only "one of" the conditions in 40 CFR 60.283a(a)(1)(i) through (vi) needs to be met in lieu of the 5 ppmdv TRS limit for digester systems, BSW systems, evaporator systems and condensate stripper systems.
- Revised the monitoring provisions in 40 CFR 60.284a(a)(1) and (2) to cite Performance Specifications 1, 3 and 5 for opacity, O_2 and TRS continuous monitoring systems, respectively, to conform with 40 CFR 60.284a(f).
- Revised the TRS monitoring provisions in 40 CFR 60.284a(a)(2) to clarify that the range of the continuous monitoring system must encompass all expected concentration values, including the zero and span values used for calibration.
- Revised the monitoring provisions in 40 CFR 60.284a(a)(2)(ii) to specify that the span of O_2 monitoring systems is 21 percent instead of 25 percent, so that air can be used instead of a calibration gas in span checks.
- Revised the monitoring and recordkeeping provisions in 40 CFR 60.284a(b)(1) and 40 CFR 60.287a(b)(3) to remove reference to BLO systems which were excluded from NSPS applicability during the 1986 NSPS review.
- Revised the O_2 correction equation in 40 CFR 60.284a(c)(1)(iii) for TRS continuous emission monitoring system (CEMS) data to clarify that the concentration to be corrected is a "12-hour average of the measured concentrations."
- Revised the excess emissions and recordkeeping provisions in 40 CFR 60.284a(d)(3)(ii) and 40 CFR 60.287a(b)(3) relating to combustion temperature measurements to clarify that the provisions apply when an incinerator is used as the combustion device.
- Added provisions to 40 CFR 60.284a(d)(3)(iii) specifying that periods of excess emissions include all times when gases from digester systems, BSW systems, evaporator systems and condensate stripper systems are not routed through the closed-vent system.
- Revised the provisions in 40 CFR 60.284a(e)(1) to change the period for calculating the monitoring allowance from quarterly to semiannual.
- Revised the citations for the EPA test methods in 40 CFR 60.285a to cite the specific appendices in parts 51 and 60 where the methods are located.
- Used "must" instead of "shall" throughout subpart BBa, consistent with plain language guidance.

B. What are the requirements during periods of startup, shutdown and malfunction?

1. Periods of Startup or Shutdown

In reviewing the standards in subpart BB, and in establishing the standards in the new subpart BBa, the EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not established alternate standards for those periods. Instead, the EPA is promulgating standards that apply at all times, including startup and shutdown periods. We analyzed continuous monitoring data and parametric methods for demonstrating continuous compliance and developed rule provisions pertaining to continuous monitoring that encompass or address startup and shutdown periods. These provisions include:

- Monitoring allowances that specify a certain number of exceedances that will not be considered as violations. These allowances were developed through review of TRS CEMS and continuous opacity monitoring system (COMS) datasets that included SSM periods, and are used in conjunction with ESP parameter monitoring (for opacity) and upper limits (for TRS) to ensure the emission standards are continuous. The PM standard is a

continuous standard that applies at all times.

- A provision for enforcement authorities to consider the uncorrected TRS concentration during periods of startup and shutdown if O_2 levels in the stack approach ambient conditions where the O_2 correction equation could cause an otherwise-compliant TRS measurement to exceed the applicable emission limit.
- For ESP parameter monitors, provisions that define excess emissions as ESP parameter measurements below the minimum requirements during times when BLS or lime mud is fired (as applicable).
- For ESP parameter monitors used on combined ESP/scrubber systems, language that allows facilities to use only secondary voltage (and not secondary current or total secondary power) to demonstrate compliance during periods of startup and shutdown because secondary current or the total secondary power calculated using secondary current may not meet the operating limit established during the performance test as BLS or lime mud is fired initially.
- For wet scrubber parameter monitors, language that allows facilities to use wet scrubber liquid flow rate (or liquid supply pressure) to demonstrate compliance during periods of startup and shutdown because pressure drop is difficult to achieve during these periods.
- For temperature monitors, a lengthened 3-hour block averaging time, and provisions that acknowledge that the minimum temperature of 1,200 °F is not a requirement during periods when an incinerator is not burning TRS (e.g., during incinerator warm-up and cool-down or when an alternative control device is used).

With the above monitoring provisions that address periods of startup and shutdown, the EPA concluded that alternative standards (e.g., work practices) during startup and shutdown are unnecessary. Two technical memoranda available in the docket for this action (EPA–HQ–OAR–2012–0640) provide our analysis of monitoring systems during startup and shutdown for pulp and paper processes subject to subpart BBa.[1] [2] Additional clarifications relative to the final rule requirements during periods of startup and shutdown are provided in section V.C of this preamble.

2. Periods of Malfunction

Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operation. However, by contrast, malfunction is defined 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. Failures that are caused in part by poor maintenance or careless operation are not malfunctions." (40 CFR 60.2) The EPA has determined that section 111 does not require that emissions occurring during periods of malfunction be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. CAA section 111 provides that the EPA set standards of performance 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. Applying the concept of "the application of the best system of emission reduction" to periods during which a source is malfunctioning presents difficulties. The "application of the best system of emission reduction" is more appropriately understood to include operating units in such a way as to avoid malfunctions.

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 "source that uses the best system of emission reduction" 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 111 and is a reasonable interpretation of the statute.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." See 40 CFR 60.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. See, e.g., *State Implementation Plans: Response to Petition for Rulemaking; Findings of Excess Emissions During Periods of Startup, Shutdown, and Malfunction; Proposed rule*, 78 FR 12460 (Feb. 22, 2013); *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 in this rule that are caused by malfunctions. (See 40 CFR 60.281a 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

[1] *Updated Review of the Continuous Emission Monitoring and Continuous Opacity Monitoring Data from the Pulp and Paper ICR Responses for NSPS Sources.*

[2] *Review of Pulp and Paper Information Collection Request (ICR) Responses Pertaining to Startup and Shutdown of Subpart BB Equipment* (March 22, 2013) (EPA–HQ–OAR–2012–0640–039 thru 045).

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 60.285a. (See 40 CFR 22.24.) The added 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 60.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance or careless operation). For example, to successfully assert the added affirmative defense, the source must prove by a preponderance of the evidence that 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 added criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 60.11(d) and to prevent future malfunctions. For example, under the added criteria, 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 in the final rule an affirmative defense 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 emission 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. 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 CAA. *Luminant Generation Co. LLC* v. *United States EPA*, 714 F.3d 841 (5th Cir. Mar. 25, 2013) (upholding the EPA's approval of affirmative defense provisions in a CAA State Implementation Plan). While "continuous" standards 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 these earlier cases may no longer represent binding precedent in light of the CAA 1977 amendments and intervening case law such as *Sierra Club* v. *EPA*, they nevertheless support the EPA's view that a system that incorporates some level of flexibility is reasonable and appropriate. The affirmative defense simply provides for a defense to civil penalties for violations that are proven to be beyond the control of the source. Through the incorporation of an affirmative defense, the EPA has formalized its approach to malfunctions. In a Clean Water Act (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*, 666 F.3d. 1174 (9th Cir. 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 final 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. The EPA is promulgating the affirmative defense applicable to malfunctions under the delegation of general regulatory authority set out in section 301(a)(1) of the CAA, 42 U.S.C. 7601(a)(1), in order to balance this tension between provisions of the Act and the practical reality, as case law recognizes, that technology sometimes fails. See generally, *Citizens to Save Spencer County* v. *U.S. Environmental Protection Agency*, 600 F.2d 844, 873 (D.C. Cir. 1979) (using section 301(a) authority to harmonize inconsistent guidelines related to the implementation of federal preconstruction review requirements).

C. What are the effective and compliance dates of the standards?

The provisions of subpart BBa being promulgated in this action are effective on April 4, 2014. Emission units that commence construction, reconstruction or modification after May 23, 2013, must comply with the provisions of subpart BBa by April 4, 2014 or upon startup, whichever is later.

The initial performance test must be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup per 40 CFR 60.8(a). The first of the 5-year repeat tests must be conducted no later than 5 years following the initial performance test, and thereafter within 5 years from the date of the previous performance test. 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?

For the reasons provided in the proposed rule preamble, in subpart BBa the EPA is requiring owners and operators of kraft pulp mills to submit electronic copies of required performance test and performance evaluation reports to the EPA's WebFIRE database. Data will be entered through an electronic emissions test report structure called the ERT. The ERT will generate an electronic report which will be submitted using the Compliance and Emissions Data Reporting Interface (CEDRI). The submitted report will be stored in both EPA's Central Data Exchange (CDX) archive (the official copy of record) and in the WebFIRE database, making access to data very straightforward and easy. A description and instructions for use 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*). A description of the WebFIRE database is available at: *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.*

The requirement to submit performance test data electronically to the EPA applies only to those performance tests conducted using test methods that are supported by the ERT.[3] The ERT supports most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at: *http://www.epa.gov/ttn/chief/ert/index.html.*

As explained in the proposal preamble, 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 also improving the quality of emission inventories and air quality regulations.

V. Summary of Significant Changes Following Proposal

The following sections summarize the significant changes made to subpart BBa for this final rule to respond to public comments and to correct technical inconsistencies or editorial errors in the proposal. A detailed discussion of these and other public comments can be found in the response-to-comments document, available in Docket ID Number EPA–HQ–OAR–2012–0640.[4]

A. TRS Vent Gas Collection

The final subpart BBa rule, as proposed, allows sources to comply with the TRS standards for digester systems, BSW systems, evaporator systems and condensate stripper systems by venting emissions to a combustion device such as a lime kiln, recovery furnace, incinerator or other device (e.g., a boiler) or a non-combustion device. Industry commenters expressed concern that the proposed provisions were not consistent with the corresponding hazardous air pollutant (HAP) reduction provisions in subpart S which specify requirements for closed-vent collection systems. Separately, another commenter expressed concern that the use of contaminated flash steam during chip steaming can lead to the release of TRS compounds, volatile organic compounds (VOC) and HAPs and urged the EPA to ensure standards are in place to prevent release of emissions.

In response to these concerns and to promote consistency with the subpart S requirements for closed-vent collection systems, we added provisions to this final rule requiring that sources collect and transport the vent gases through HVLC or LVHC closed-vent systems to incineration or other control devices, to match what is required under subpart S. We added definitions for "closed-vent system," "high-volume, low-concentration (HVLC) closed-vent system," and "low-volume, high-concentration (LVHC) closed-vent system" to this final rule to eliminate any conflicts with the subpart S excess emission allowances for closed-vent systems. We defined excess emissions as all times when gases are not routed through the closed-vent system. We also revised the definition for "digester system" to specifically include chip bins using live steam (flash steam) to clarify that these units are subject to regulation under subpart BBa as part of the digester system.

Further, an industry commenter made the specific comment that, with the removal of the SSM exemption, there are no provisions in subpart BBa specifically addressing short periods of safety-related venting of gases from digester systems, brown stock washer systems, multiple-effect evaporator systems or condensate stripper systems. According to the commenter, best available technology includes unavoidable periods when vent gases cannot be routed to the control device for safety reasons or when the control device is inoperable or necessarily operating at a reduced rate due to a malfunction. The subpart S excess emission allowances (see 40 CFR 63.443(e)(1)–(3)), currently address these types of excess emissions. The SSM exemption was previously removed from subpart S (77 FR 55698). The commenter noted that they provided more detail in previously submitted comments on subpart S which they attached for consideration. The commenter recommended that the EPA adopt the excess emission provisions in subpart S for digester, brown stock washer, evaporator and stripper systems covered by subpart BBa. We did not intend to propose a standard that removed the use of these allowances for NSPS units, creating a standard more stringent than the NESHAP. Therefore, we have added language in this final rule that recognizes the current subpart S excess emission provisions for closed-vent systems. (Further discussion of the EPA's anticipated review of the subpart S excess emission provisions is provided below.) These provisions define excess emissions as all times when gases are not routed through the closed-vent system. (See 40 CFR 60.284a(d).) We also addressed short periods of safety-related venting in 40 CFR 60.284a(e), which provides limited allowances of 1 percent of semiannual operating time for LVHC systems, or 4 percent of semiannual operating time for HVLC or combined LVHC/HVLC systems. As long as these time periods are not exceeded, excess emissions associated with short periods of safety-related venting will not be considered in violation of the closed-vent system requirements added to 40 CFR 60.283a(a)(1)(i) through (iii) and (v). Affected facilities are required to maintain and operate with good air pollution control practice for minimizing emissions during periods of excess emissions (including during safety-related venting), as specified in 40 CFR 60.284a(e)(2) of subpart BBa.

We acknowledge that representatives of the pulp and paper industry have submitted a petition for reconsideration of the final 40 CFR part 63, subpart S risk and technology (RTR) rule relating to safety-related venting of pulp mill vent gases.[5] Additionally, in the subpart S RTR action (77 FR 55698) we deferred action on the review of the 40 CFR 63.443(e) excess emission allowances. We have acted at this time to create consistency between subpart BBa and subpart S in how these episodes are handled. However, we note that, when the EPA reviews the subpart S excess emission allowances, we will consider whether actions that we take after conducting that subpart S review should result in revisions to the NSPS for kraft pulp mills. It should also be noted that the standards in subpart S apply to HAP emissions from a broad range of pulp mill sources and will be applicable to existing sources, while the subpart BBa TRS standards will apply only for the small subset of subpart S sources that are constructed, modified or reconstructed after May 23, 2013. Consequently, if the subpart S standards are amended to become more stringent

[3] As of March 2014, Methods 5, 17 and 202 are the test methods referenced in subpart BBa that are included in ERT. Methods 16, 16A, 16B, and 16C for TRS measurement are not yet supported by ERT. However, Method 16 (and variant) testing conducted after Methods 16, 16A, 16B, 16C are programmed into the ERT will be required to be reported electronically.

[4] See the memorandum in the docket titled, *Kraft Pulp Mills New Source Performance Review (40 CFR Part 60, Subpart BBa), Final Amendments: Response to Public Comments on May 23, 2013 Proposal.*

[5] Letter from P. Noe, AF&PA, to Lisa Jackson. *Petition for Reconsideration of National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry; Final Rule,* 77 FR 55698 (Sept. 11, 2012).

with respect to pulp mill safety-related venting, then those amended subpart S standards will apply equally to subpart BBa sources, because all subpart BBa sources (as well as all subpart BB sources and any sources subject to future revisions to the Kraft Pulp Mill NSPS) will also be subject to subpart S (including any revisions made to it in the future), regardless of when the next NSPS review to update subpart BBa is performed.

B. Startup, Shutdown and Malfunction

One commenter supported and multiple commenters objected to our proposal to remove the SSM exemption from the subpart BBa standards. The rationale for our removal of the SSM exemption was provided in the preamble to the proposed rule, is provided in section IV.B of this preamble, and is also discussed in the response-to-comments document [6] along with a description of the revisions to the NSPS monitoring requirements made to ensure that the NSPS provisions remain achievable following removal of the SSM exemption.

Multiple commenters expressed confusion regarding the provisions in the proposed rule briefly stating that the PM and TRS standards apply at all times (40 CFR 60.282a(b) and 40 CFR 60.283a(b), respectively). The comments revealed confusion regarding which paragraphs of the NSPS General Provisions relating to SSM are superseded by subpart BBa or remain applicable. In response to these comments, we revised 40 CFR 60.282a(b) and 40 CFR 60.283a(b) to clarify that the standards apply at all times as specified in the monitoring and testing provisions of the rule (40 CFR 60.284a and 40 CFR 60.285a) and to clarify the relationship between the continuous standards and provisions for testing, monitoring and the monitoring allowances in subpart BBa. We also offer the following clarifications relative to the relationship between the General Provisions and subpart BBa:

- The definitions of SSM in 40 CFR 60.2 apply to subpart BBa.
- The requirement to maintain records of SSM periods and periods when continuous monitoring systems are inoperative under 40 CFR 60.7(b) applies to subpart BBa.
- The requirements under 40 CFR 60.7(c)(2) to identify in the excess emissions report each period of excess emissions that occurs during SSM and the nature of any malfunction apply to subpart BBa.
- Inclusion of startup and shutdown in the summary report format provided in 40 CFR 60.7(d) applies for subpart BBa.
- The 40 CFR 60.11(c) exemption from the opacity standards during SSM is superseded for subpart BBa by 40 CFR 60.282a(c).
- The 40 CFR 60.11(d) requirement to use good air pollution control practices at all times including SSM applies to subpart BBa.

Furthermore, we added a clarifying statement to 40 CFR 60.285a(a) to repeat only the portion of 40 CFR 60.8(c) that applies under subpart BBa (i.e., the requirement that performance tests be conducted under representative conditions applies). The SSM exemption phrase "nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard" was eliminated from the revised wording of 40 CFR 60.8(c) incorporated into subpart BBa in light of the DC Circuit's decision in *Sierra Club* v. *EPA* vacating the 40 CFR part 63 SSM exemption provisions. The revised wording in 40 CFR 60.285a(a) of subpart BBa supersedes 40 CFR 60.8(c).

C. Opacity Monitoring

One commenter questioned whether a source controlled by an ESP/scrubber combination would be relieved from meeting the opacity requirements in this final rule. In response to this comment, we revised the opacity standards for recovery furnaces and lime kilns to clarify that units equipped with a combination ESP and wet scrubber system are not subject to the opacity standards, because opacity monitoring is not appropriate for these units. This does not create an exemption or a standard that does not apply at all times because continuous compliance with the filterable PM standards is demonstrated through ESP and wet scrubber parameter monitoring for combined ESP/scrubber systems.

D. TRS and Oxygen Monitoring

Measurements exceeding instrument span. Three commenters requested that the EPA clarify the procedure for reporting and treatment of uncorrected TRS concentrations that exceed the span value (30 ppmdv) for the TRS CEMS instrument. In response to these comments, we note that data above the instrument span have value and are required to be included in any CEMS hourly average or other long-term rolling average calculation; otherwise, facilities could inappropriately dismiss noncompliant values as invalid data. Consequently, we added language to the final rule to clarify that the range of the continuous monitoring system must encompass all expected concentration values, including the zero and span values used for calibration.

Recovery furnace upper limit. One commenter argued that it was inappropriate for the EPA to use data from straight recovery furnaces to establish the TRS monitoring allowance upper limit for cross recovery furnaces. In response to this comment, we revised this final rule to clarify that the 1-percent allowance, restricted to 30 ppmdv, applies to TRS emissions from straight recovery furnaces. The cross recovery furnace TRS emission limit is higher than the straight recovery TRS limit for three technical reasons. First, the sulfur content of the semichemical liquor is higher than traditional kraft liquor. Second, the heat content of the liquor is lower because it contains less organic material than kraft liquor due to higher pulping yields. Third, the heavier sulfur loading and the lower operating temperature puts a restriction on the amount of excess O_2 available to oxidize the sulfur compounds. Because we do not have continuous monitoring data for cross recovery furnaces to analyze (with no known cross recovery furnaces subject to NSPS at this time), we are setting the upper TRS limit for cross recovery furnaces at the instrument span of 50 ppmdv for these units. This upper limit can be reevaluated during the next NSPS review should data become available for cross recovery furnaces subject to NSPS in the future.

E. Temperature Monitoring

One commenter recommended that the temperature monitoring requirement should only apply when TRS control is achieved in a stand-alone incinerator and requested that the EPA make this clarification in this final rule. The commenter noted that temperature monitoring is not required in subpart S for boilers, lime kilns and recovery furnaces that combust pulping vent gases because these units normally operate at temperatures higher than 1,200 °F. We revised the relevant provisions of subpart BBa to clarify that combustion temperature monitoring is required only when an incinerator is used as the combustion device in response to this comment.

[6] See the memorandum in the docket titled, *Kraft Pulp Mills New Source Performance Review (40 CFR Part 60, Subpart BBa), Final Amendments: Response to Public Comments on May 23, 2013 Proposal.*

F. ESP Parameter Monitoring

Two commenters requested that the EPA add total secondary power as an alternative to monitoring ESP secondary voltage and secondary current for recovery furnace ESPs to be consistent with the monitoring alternative provided in the proposed rule for lime kiln ESPs. We made the conforming edits requested to clarify our intent, as proposed, that monitoring of total secondary power is an alternative for recovery furnace ESPs.

Another commenter requested that the EPA use only ESP secondary voltage monitoring to determine compliance during periods of startup and shutdown for combined ESP/scrubber control systems. The commenter explained that the first 12-hour block average ESP secondary current (or total secondary power) may not be within the range achieved during the last performance test, as firing of BLS or lime mud increases or decreases during startup or shutdown, but the ESP would still be operating optimally using its automated power management system. The commenter requested that the EPA exclude from the definition of excess emissions all 12-hour average measurements of secondary current (or total secondary power) during startup and shutdown that are less than the site-specific operating parameter limits, as it has done for scrubber pressure drop. We agree with the commenter that secondary current (or total secondary power) can vary during startup and shutdown. We changed the definition of ESP-related excess emissions for combined ESP/scrubber controls in 40 CFR 60.284a(d)(5) in response to this comment to include all 12-hour block averages of ESP secondary voltage below the minimum operating limit at all times (including startup and shutdown), and 12-hour block averages of secondary current (or total secondary power) below the minimum operating limit at all times except during startup and shutdown. The rule changes make the startup/shutdown accommodations for ESPs comparable to the parameter monitoring requirements for wet scrubbers during startup and shutdown. This definitional change does not apply for ESP systems that have longer averaging periods in conjunction with an opacity limit. For further discussion, see the response-to-comments document found in the docket.

G. Averaging Period for Determining Monitoring Allowances

In response to our request for comment on whether a quarterly or semiannual period would be more appropriate for calculation of the monitoring allowances in 40 CFR 60.284a(e), multiple commenters supported a semiannual period. One state agency commenter specifically supported changing the ESP parameter averaging period from quarterly to semiannually when an opacity monitor is also used on the ESP. The commenter also supported using a semiannual instead of a quarterly basis for determining the TRS and opacity monitoring allowances. In response to these comments and consistent with the semiannual reporting frequency for subpart BBa, we revised the period for calculating the opacity and TRS monitoring allowances from quarterly to semiannually. We made a corresponding change to a semiannual basis for the ESP parameter averaging period for ESPs that also monitor opacity.

H. Other Miscellaneous Changes

A few additional changes were made to the proposed rule either as a result of public comments, to correct references or to ensure conformity among the various rule sections. These changes are described below.

BLO systems. One commenter asked that the EPA remove outdated references to BLO systems from the rule because subpart BBa does not contain any specific requirements for these systems. We agree with this editorial change and removed the definition of "black liquor oxidation system" and other inadvertently remaining references to BLO systems from this final rule. The 1986 review of the kraft pulp mills NSPS removed the BLO system from the list of regulated emission units.

Testing frequency. One commenter requested that the EPA revise the repeat testing frequency from once every 60 months to once every 5 years to provide maximum operational flexibility. In particular, the requested change would make clear that the repeat testing could be done at any point during the fifth calendar year (which is consistent with the requirements for CAA title V permitting) as opposed to requiring testing to be done during the 60th month. We agree with the commenter and revised the testing provisions of this final rule accordingly.

Performance specifications. In the proposed rule, we specified that sources must install, certify and operate their opacity and TRS continuous monitoring systems in accordance with Performance Specifications 1 and 5, respectively, in Appendix B to 40 CFR part 60. To correct an oversight, we added a citation to this final rule for Performance Specification 3 for the O_2 continuous monitoring system used to correct the TRS CEMS data for O_2 concentration.

Incorporation by reference. In reviewing the testing provisions in subpart BBa for the final rule, we noted that the test method for determining whether a kraft recovery furnace is a straight or cross recovery furnace, which is cited in this final rule and incorporated by reference in 40 CFR 60.17 as TAPPI T624 os-68, is out-of-date, as is the address for obtaining a copy of the method. We updated the testing provisions in this final rule and the IBR provisions in 40 CFR 60.17 to cite the latest version of the method—TAPPI T624 cm-11. We also updated 40 CFR 60.17 to cite the current address for obtaining a copy of the method.

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

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

The EPA presented estimates of the impacts for subpart BBa, which revises the performance standards for new, modified or reconstructed emission units at kraft pulp mills, in the preamble to the proposed rule and in the docket for this rulemaking. (See 78 FR 31331–31332, and the memorandum, *Emissions Inventory for Kraft Pulp Mills and Costs/Impacts of the Section 111(b) Review of the Kraft Pulp Mills NSPS.*) These impact estimates have not changed since proposal because we have not changed any rule requirements in a way that would alter the projected number of affected facilities or costs of compliance. While we added language to subpart BBa to clarify that TRS emissions from new, modified or reconstructed pulping emission sources must be delivered to incineration or other controls through a closed-vent collection system as required under 40 CFR 63.450 of subpart S, there is no incremental cost associated with this requirement in subpart BBa because the closed-vent collection system standards are already required for new and existing sources under subpart S.

The EPA estimates that the total increase in nationwide annual cost associated with this final rule is $389,900 for all of the emission units projected to be constructed, modified or reconstructed between 2013 and 2018. Costs are based on the third quarter of 2012. The impacts are expressed as incremental differences between the impacts of emission units complying with subpart BBa and the baseline (e.g.,

NSPS subpart BB or NESHAP subpart MM) requirements for these sources. The impacts represent emission units at kraft pulp mills projected to commence construction, reconstruction or modification over the 5 years following May 23, 2013. No additional control devices or other equipment are expected to be needed to meet the NSPS requirements beyond those that would already be installed to meet the baseline requirements for these emission units. Thus, no emission reductions, energy impacts or secondary air emission impacts are expected to result from this final rule.

This final action is not expected to induce measurable changes in the average national price and production of pulp and paper products. Hence, the overall economic impact of this NSPS should be minimal on the affected industries and their consumers. For more information, please refer to the memorandum, *Economic Impact Analysis for the Section 111(b) Review of the Kraft Pulp Mills New Source Performance Standards Subpart BB,* in the docket for this rulemaking.

VII. Statutory and Executive Order Reviews

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

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

The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the memorandum, *Economic Impact Analysis for the Section 111(b) Review of the Kraft Pulp Mills New Source Performance Standards Subpart BB.* A copy of the analysis is available 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 Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* The information collection requirements are not enforceable until OMB approves them.

These revisions to the NSPS for Kraft Pulp Mills for future affected sources include different emission limits and continuous monitoring requirements and additional performance testing from what is in subpart BB. The additional performance testing requirements for recovery furnaces, SDTs and lime kilns include initial testing for condensable PM and 5-year repeat testing for filterable PM, condensable PM and TRS. The monitoring requirements include a different opacity limit and monitoring allowance for recovery furnaces, restriction of the monitoring allowances for TRS to an upper concentration limit, continuous opacity monitoring for lime kilns equipped with ESPs and continuous ESP parameter monitoring for recovery furnaces and lime kilns equipped with ESPs. These testing and monitoring requirements are in addition to the initial performance testing and continuous monitoring requirements described in section IV.A of this preamble, which are required under the current subpart BB.

The recordkeeping and reporting requirements associated with these testing and monitoring provisions 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 the EPA policies set forth in 40 CFR part 2, subpart B.

When a malfunction occurs, sources must report it according to the applicable reporting requirements of 40 CFR part 60, subpart BBa. An affirmative defense to civil penalties for violations of emission standards that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. 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 final rule, the EPA is considering the affirmative defense in its estimate of burden in the information collection request (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 shows what the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports and records, including the root cause analysis associated with a single incident totals approximately $3,375, and is based on the time and effort required of a source to review relevant data, interview plant employees and document the events surrounding a malfunction that has caused a violation of an emission limit. The estimate also includes time to produce and retain the records and reports for submission to the EPA.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, the EPA cannot reliably predict the severity and frequency of malfunction-related excess emission 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 emission standards during malfunctions. Of the number of violation events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition of a malfunction in 40 CFR 60.2), and only a subset of violations caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, the EPA believes 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, the EPA estimates no more than two such occurrences for all sources subject to 40 CFR part 60, subpart BBa over the 3-year period covered by the ICR. The EPA expects to gather information on such events in the future and will revise this estimate as better information becomes available.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 1,905 labor-hours per year at a cost of $186,324/yr. The annualized capital costs are estimated at $411,300/yr. The annual operating and maintenance (O&M) costs are $155,880/yr. The total annualized capital and O&M costs are $567,180/yr. Burden is defined in 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 number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act

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

For purposes of assessing the impacts of this final rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This certification is based on the economic impact of this action to all affected small entities. Only two small entities may be impacted by this final rule. The EPA estimates that all affected small entities will have annualized costs of less than 0.1 percent of their sales. Thus, the EPA concludes that this final rule will not have a significant economic impact on a substantial number of small entities.

For more information on the small entity impacts associated with this rule, please refer to the memorandum, *Economic Impact Analysis for the Section 111(b) Review of the Kraft Pulp Mills New Source Performance Standards Subpart BB,* in the public docket. Although this final 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 final rule on small entities. When developing these standards, the EPA took special steps to ensure that the burdens imposed on small entities were minimal. The EPA conducted several meetings with the industry trade association to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting and impacts on existing sources that are modified.

D. Unfunded Mandates Reform Act

This final rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or to the private sector in any one year. This final rule is not expected to impact state, local or tribal governments. The nationwide annualized cost of this final rule for affected industrial sources is estimated to be $389,900/yr. Thus, this final rule is not subject to the requirements of sections 202 and 205 of the Unfunded Mandates Reform Act (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. This final rule will not apply to such governments and will not impose any obligations upon them.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. 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. Thus, Executive Order 13132 does not apply to this rule.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. This final rule imposes requirements on owners and operators of kraft pulp mills and not tribal governments. The EPA does not know of any kraft pulp mills owned or operated by Indian tribal governments. However, if there are any, the effect of this rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 13045 (62 FR 19885, April 22, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is based solely on an analysis of the degree of emission reduction that is achievable through the application of the best system of emissions reduction, as provided in CAA section 111.

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

This action is not subject to Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995, 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. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, 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 rulemaking involves technical standards. The EPA has decided to use one VCS in this rulemaking. The VCS, ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," is cited in this rule for its manual method of measuring the content of the exhaust gas as an acceptable alternative to EPA Method 3B of 40 CFR part 60, appendix A–2. This standard is available at *http://www.asme.org* or by mail at the American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016–5990.

The EPA has identified two other VCS as being potentially applicable to this final rule. The first, ASTM D7520–09, is an alternative to Method 9 (see part 60, appendix A–4 for a description of Method 9). This final rule currently provides the use of COMS as an alternative to Method 9; therefore, the EPA has decided not to use ASTM D7520–09 in this rulemaking. The second, ANSI/ASME PTC 19–10–1981–Part 10, is an alternative to Method 16A (see part 60, appendix A–6 for a description of Method 16A). The EPA is incorporating this VCS as an alternative to Method 3B above, but is not incorporating it as an alternative to Method 16A because it is an alternative for only the manual portion and not the instrumental portion of Method 16A, and sources are already allowed four EPA methods for measuring TRS (Methods 16, 16A, 16B and 16C). See the docket for this rule for the reasons for these determinations.

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 practicable 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 it is unknown where new facilities will be located and the EPA does not expect new facilities to be built. However, the agency has reviewed the areas surrounding all existing kraft pulp mills to determine if there is an overrepresentation of minority, low income or indigenous populations near the sources, such that they may currently face disproportionate risks from pollutants.

To gain a better understanding of the source category and near source populations, the EPA conducted a demographic analysis on the source category for this rulemaking. This analysis only gives some indication of the prevalence of subpopulations that may be exposed to air pollution from the sources and, therefore, would be those populations that may be expected to benefit most from this regulation; it does not identify the demographic characteristics of the most highly affected individuals or communities, nor does it quantify the level of risk faced by those individuals or communities. The data show that most demographic categories were below or within 20 percent of their corresponding national averages except for the African American population percentage within three miles of any source potentially affected by this rulemaking. This segment of the population exceeds the national average by 5 percentage points (18 percent v. 13 percent), or plus 38 percent. There is no indication that this segment of the population faces an unacceptable risk from emissions from these sources. However, the additional information that will be collected from the increase in testing requirements with this rule is expected to better inform the agency of the emissions associated with this source category. This will ensure better compliance with this final rule and will result in this rule being more protective of human health. The demographic analysis results and the details concerning their development are presented in the September 18, 2012, memorandum titled, *Environmental Justice Review: Kraft Pulp Mills NSPS*, a copy of which is available in the docket for this action (EPA–HQ–OAR–2012–0640).

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 this final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This final rule will be effective on April 4, 2014.

List of Subjects in 40 CFR Part 60

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

Dated: March 14, 2014.

Gina McCarthy,

Administrator.

As described in the preamble above, the EPA amends 40 CFR part 60 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.*

Subpart A—[Amended]

■ 2. Section 60.17 is amended by:
■ a. Revising paragraph (f) introductory text,
■ b. Revising paragraph (f)(14),
■ c. Revising paragraph (o) introductory text, and
■ d. Revising paragraph (o)(1).

The amendments read as follows:

§ 60.17 Incorporations by reference.

* * * * *

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

(14) ASME/ANSI 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 to subpart EEEE, tables 2 and 4 to subpart FFFF, table 2 to subpart JJJJ, § 60.285a(f), §§ 60.4415(a), 60.2145(s) and (t), 60.2710(s) (t), and (w), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§ 60.5406(c) and 60.5413(b).

* * * * *

(o) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Suite 115, Peachtree Corners, GA 30092, Telephone (800) 332–8686, and is also available at the following Web site: *http://www.tappi.org.*

(1) TAPPI Method T 624 cm-11, (Copyright 2011), IBR approved, for §§ 60.285(d) and 60.285a(d).

* * * * *

■ 3. Section 60.280 is amended by revising paragraph (b) to read as follows:

§ 60.280 Applicability and designation of affected facility.

* * * * *

(b) Except as noted in § 60.283(a)(1)(iv), any facility under paragraph (a) of this section that commences construction, reconstruction, or modification after September 24, 1976, and on or before May 23, 2013 is subject to the requirements of this subpart. Any facility under paragraph (a) of this section that commences construction, reconstruction, or modification after May 23, 2013 is subject to the requirements of subpart BBa of this part.

■ 4. Add subpart BBa to read as follows:

Subpart BBa—Standards of Performance for Kraft Pulp Mill Affected Sources for Which Construction, Reconstruction, or Modification Commenced After May 23, 2013

Sec.

Subpart BBa—Standards of Performance for Kraft Pulp Mill Affected Sources for Which Construction, Reconstruction, or Modification Commenced After May 23, 2013

§ 60.280a Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in kraft pulp mills: digester system, brown stock washer system, multiple-effect evaporator system, recovery furnace, smelt dissolving tank, lime kiln and condensate stripper system. In pulp mills where kraft pulping is combined with neutral sulfite semichemical pulping, the provisions of this subpart are applicable when any portion of the material charged to an affected facility is produced by the kraft pulping operation.

(b) Except as noted in § 60.283a(a)(1)(iv), any facility under paragraph (a) of this section that commences construction, reconstruction or modification after May 23, 2013, is subject to the requirements of this subpart. Any facility under paragraph (a) of this section that commenced construction, reconstruction, or modification after September 24, 1976, and on or before May 23, 2013 is subject to the requirements of subpart BB of this part.

§ 60.281a Definitions.

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

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

Black liquor solids (BLS) means the dry weight of the solids which enter the recovery furnace in the black liquor.

Brown stock washer system means brown stock washers and associated knotters, vacuum pumps, and filtrate tanks used to wash the pulp following the digester system. Diffusion washers are excluded from this definition.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from an emission point to a control device.

Condensable particulate matter, for purposes of this subpart, means particulate matter (PM) measured by EPA Method 202 of Appendix M of 40 CFR part 51 that is vapor phase at stack conditions, but condenses and/or reacts upon cooling and dilution in the ambient air to form solid or liquid PM immediately after discharge from the stack.

Condensate stripper system means a column, and associated condensers, used to strip, with air or steam, total reduced sulfur (TRS) compounds from condensate streams from various processes within a kraft pulp mill.

Cross recovery furnace means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains more than 7 weight percent of the total pulp solids from the neutral sulfite semichemical process and has a green liquor sulfidity of more than 28 percent.

Digester system means each continuous digester or each batch digester used for the cooking of wood in white liquor, and associated flash tank(s), blow tank(s), chip steamer(s) including chip bins using live steam, and condenser(s).

Filterable particulate matter, for purposes of this subpart, means particulate matter measured by EPA Method 5 of Appendix A–3 of this part.

Green liquor sulfidity means the sulfidity of the liquor which leaves the smelt dissolving tank.

High volume, low concentration (HVLC) closed-vent system means the gas collection and transport system used to convey gases from the brown stock washer system to a control device.

Kraft pulp mill means any stationary source which produces pulp from wood by cooking (digesting) wood chips in a water solution of sodium hydroxide and sodium sulfide (white liquor) at high temperature and pressure. Regeneration of the cooking chemicals through a recovery process is also considered part of the kraft pulp mill.

Lime kiln means a unit used to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

Low volume, high concentration (LVHC) closed-vent system means the gas collection and transport system used to convey gases from the digester system, condensate stripper system, and multiple-effect evaporator system to a control device.

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

Multiple-effect evaporator system means the multiple-effect evaporators and associated condenser(s) and hotwell(s) used to concentrate the spent cooking liquid that is separated from the pulp (black liquor).

Neutral sulfite semichemical pulping operation means any operation in which pulp is produced from wood by cooking (digesting) wood chips in a solution of sodium sulfite and sodium bicarbonate, followed by mechanical defibrating (grinding).

Recovery furnace means either a straight kraft recovery furnace or a cross recovery furnace, and includes the direct-contact evaporator for a direct-contact furnace.

Smelt dissolving tank means a vessel used for dissolving the smelt collected from the recovery furnace.

Straight kraft recovery furnace means a furnace used to recover chemicals

consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains 7 weight percent or less of the total pulp solids from the neutral sulfite semichemical process or has green liquor sulfidity of 28 percent or less.

Total reduced sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide that are released during the kraft pulping operation and measured by Method 16 of Appendix A–6 of this part.

§ 60.282a Standard for filterable particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any modified recovery furnace any gases which:

(i) Contain filterable particulate matter in excess of 0.10 gram per dry standard cubic meter (g/dscm) (0.044 grain per dry standard cubic foot (gr/dscf)) corrected to 8-percent oxygen.

(ii) Exhibit 20-percent opacity or greater, where an electrostatic precipitator (ESP) emission control device is used, except where it is used in combination with a wet scrubber.

(2) From any new or reconstructed recovery furnace any gases which:

(i) Contain filterable particulate matter in excess of 0.034 g/dscm (0.015 gr/dscf) corrected to 8-percent oxygen.

(ii) Exhibit 20-percent opacity or greater, where an ESP emission control device is used, except where it is used in combination with a wet scrubber.

(3) From any modified or reconstructed smelt dissolving tank, or from any new smelt dissolving tank that is not associated with a new or reconstructed recovery furnace subject to the provisions of paragraph (a)(2) of this section, any gases which contain filterable particulate matter in excess of 0.1 gram per kilogram (g/kg) (0.2 pound per ton (lb/ton)) of black liquor solids (dry weight).

(4) From any new smelt dissolving tank associated with a new or reconstructed recovery furnace subject to the provisions of paragraph (a)(2) of this section, any gases which contain filterable particulate matter in excess of 0.060 g/kg (0.12 lb/ton) black liquor solids (dry weight).

(5) From any modified lime kiln any gases which:

(i) Contain filterable particulate matter in excess of 0.15 g/dscm (0.064 gr/dscf) corrected to 10-percent oxygen.

(ii) Exhibit 20-percent opacity or greater, where an ESP emission control device is used, except where it is used in combination with a wet scrubber.

(6) From any new or reconstructed lime kiln any gases which:

(i) Contain filterable particulate matter in excess of 0.023 g/dscm (0.010 gr/dscf) corrected to 10-percent oxygen.

(ii) Exhibit 20-percent opacity or greater, where an ESP emission control device is used, except where it is used in combination with a wet scrubber.

(b) These standards apply at all times as specified in §§ 60.284a and 60.285a.

(c) The exemptions to opacity standards under 40 CFR 60.11(c) do not apply to subpart BBa.

§ 60.283a Standard for total reduced sulfur (TRS).

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart must cause to be discharged into the atmosphere:

(1) From any digester system, brown stock washer system, multiple-effect evaporator system, or condensate stripper system any gases which contain TRS in excess of 5 parts per million (ppm) by volume on a dry basis, corrected to 10-percent oxygen, unless one of the following conditions are met:

(i) The gases are collected in an LVHC or HVLC closed-vent system meeting the requirements of § 63.450 and combusted in a lime kiln subject to the provisions of either paragraph (a)(5) of this section or § 60.283(a)(5); or

(ii) The gases are collected in an LVHC or HVLC closed-vent system meeting the requirements of § 63.450 and combusted in a recovery furnace subject to the provisions of either paragraphs (a)(2) or (3) of this section or § 60.283(a)(2) or (3); or

(iii) The gases are collected in an LVHC or HVLC closed-vent system meeting the requirements of § 63.450 and combusted with other waste gases in an incinerator or other device, or combusted in a lime kiln or recovery furnace not subject to the provisions of this subpart (or subpart BB of this part), and are subjected to a minimum temperature of 650 °C (1200 °F) for at least 0.5 second; or

(iv) It has been demonstrated to the Administrator's satisfaction by the owner or operator that incinerating the exhaust gases from a new, modified, or reconstructed brown stock washer system is technologically or economically unfeasible. Any exempt system will become subject to the provisions of this subpart if the facility is changed so that the gases can be incinerated.

(v) The gases from the digester system, brown stock washer system, or condensate stripper system are collected in an LVHC or HVLC closed-vent system meeting the requirements of § 63.450 and controlled by a means other than combustion. In this case, this system must not discharge any gases to the atmosphere which contain TRS in excess of 5 ppm by volume on a dry basis, uncorrected for oxygen content.

(vi) The uncontrolled exhaust gases from a new, modified, or reconstructed digester system contain TRS less than 0.005 g/kg (0.01 lb/ton) air dried pulp (ADP).

(2) From any straight kraft recovery furnace any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 8-percent oxygen.

(3) From any cross recovery furnace any gases which contain TRS in excess of 25 ppm by volume on a dry basis, corrected to 8-percent oxygen.

(4) From any smelt dissolving tank any gases which contain TRS in excess of 0.016 g/kg (0.033 lb/ton) of black liquor solids as hydrogen sulfide (H_2S).

(5) From any lime kiln any gases which contain TRS in excess of 8 ppm by volume on a dry basis, corrected to 10-percent oxygen.

(b) These standards apply at all times as specified in §§ 60.284a and 60.285a.

§ 60.284a Monitoring of emissions and operations.

(a) Any owner or operator subject to the provisions of this subpart must install, calibrate, maintain, and operate the continuous monitoring systems specified in paragraphs (a)(1) and (2) of this section:

(1) A continuous monitoring system to monitor and record the opacity of the gases discharged into the atmosphere from any recovery furnace or lime kiln using an ESP emission control device, except as specified in paragraph (b)(4) of this section. The span of this system must be set at 70-percent opacity. You must install, certify, and operate the continuous opacity monitoring system in accordance with Performance Specification (PS) 1 in Appendix B to 40 CFR part 60.

(2) Continuous monitoring systems to monitor and record the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from any lime kiln, recovery furnace, digester system, brown stock washer system, multiple-effect evaporator system, or condensate stripper system, except where the provisions of § 60.283a(a)(1)(iii) or (iv) apply. You must install, certify, and operate the continuous TRS monitoring system in accordance with Performance Specification (PS) 5 in Appendix B to 40

CFR part 60. You must install, certify, and operate the continuous oxygen monitoring system in accordance with Performance Specification (PS) 3 in Appendix B to 40 CFR part 60. These systems must be located downstream of the control device(s). The range of the continuous monitoring system must encompass all expected concentration values, including the zero and span values used for calibration. The spans of these continuous monitoring system(s) must be set:

(i) At a TRS concentration of 30 ppm for the TRS continuous monitoring system, except that for any cross recovery furnace the span must be set at 50 ppm.

(ii) At 21-percent oxygen for the continuous oxygen monitoring system.

(b) Any owner or operator subject to the provisions of this subpart must install, calibrate, maintain, and operate the following continuous parameter monitoring devices specified in paragraphs (b)(1) through (4) of this section.

(1) For any incinerator, a monitoring device for the continuous measurement of the combustion temperature at the point of incineration of effluent gases which are emitted from any digester system, brown stock washer system, multiple effect evaporator system, or condensate stripper system where the provisions of § 60.283a(a)(1)(iii) apply. The monitoring device is to be certified by the manufacturer to be accurate within ±1 percent of the temperature being measured.

(2) For any recovery furnace, lime kiln, or smelt dissolving tank using a wet scrubber emission control device:

(i) A monitoring device for the continuous measurement of the pressure drop of the gas stream through the control equipment. The monitoring device is to be certified by the manufacturer to be accurate to within a gage pressure of ±500 Pascals (±2 inches water gage pressure).

(ii) A monitoring device for the continuous measurement of the scrubbing liquid flow rate. The monitoring device used for continuous measurement of the scrubbing liquid flow rate must be certified by the manufacturer to be accurate within ±5 percent of the design scrubbing liquid flow rate.

(iii) As an alternative to pressure drop measurement under paragraph (b)(2)(i) of this section, a monitoring device for measurement of fan amperage may be used for smelt dissolving tank dynamic scrubbers that operate at ambient pressure or for low-energy entrainment scrubbers where the fan speed does not vary.

(iv) As an alternative to scrubbing liquid flow rate measurement under paragraph (b)(2)(ii) of this section, a monitoring device for measurement of scrubbing liquid supply pressure may be used. The monitoring device is to be certified by the manufacturer to be accurate within ±15 percent of design scrubbing liquid supply pressure. The pressure sensor or tap is to be located close to the scrubber liquid discharge point. The Administrator may be consulted for approval of alternative locations.

(3) For any recovery furnace or lime kiln using an ESP emission control device, the owner or operator must use the continuous parameter monitoring devices specified in paragraphs (b)(3)(i) and (ii) of this section.

(i) A monitoring device for the continuous measurement of the secondary voltage of each ESP collection field.

(ii) A monitoring device for the continuous measurement of the secondary current of each ESP collection field.

(iii) Total secondary power may be calculated as the product of the secondary voltage and secondary current measurements for each ESP collection field and used to demonstrate compliance as an alternative to the secondary voltage and secondary current measurements.

(4) For any recovery furnace or lime kiln using an ESP followed by a wet scrubber, the owner or operator must use the continuous parameter monitoring devices specified in paragraphs (b)(2) and (3) of this section. The opacity monitoring system specified in paragraph (a)(1) of this section is not required for combination ESP/wet scrubber control device systems.

(c) *Monitor operation and calculations.* Any owner or operator subject to the provisions of this subpart must follow the procedures for collecting and reducing monitoring data and setting operating limits in paragraphs (c)(1) through (6) of this section. Subpart A of this part specifies methods for reducing continuous opacity monitoring system data.

(1) Any owner or operator subject to the provisions of this subpart must, except where the provisions of § 60.283a(a)(1)(iii) or (iv) apply, perform the following:

(i) Calculate and record on a daily basis 12-hour average TRS concentrations for the two consecutive periods of each operating day. Each 12-hour average must be determined as the arithmetic mean of the appropriate 12 contiguous 1-hour average TRS concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(ii) Calculate and record on a daily basis 12-hour average oxygen concentrations for the two consecutive periods of each operating day for the recovery furnace and lime kiln. These 12- hour averages must correspond to the 12-hour average TRS concentrations under paragraph (c)(1)(i) of this section and must be determined as an arithmetic mean of the appropriate 12 contiguous 1-hour average oxygen concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(iii) Using the following equation, correct all 12-hour average TRS concentrations to 10 volume percent oxygen, except that all 12-hour average TRS concentrations from a recovery furnace must be corrected to 8 volume percent oxygen instead of 10 percent, and all 12-hour average TRS concentrations from a facility to which the provisions of § 60.283a(a)(1)(v) apply must not be corrected for oxygen content:

$$C_{corr} = C_{meas} \times (21 - X/21 - Y)$$

Where:

C_{corr} = the concentration corrected for oxygen.

C_{meas} = the 12-hour average of the measured concentrations uncorrected for oxygen.

X = the volumetric oxygen concentration in percentage to be corrected to (8 percent for recovery furnaces and 10 percent for lime kilns, incinerators, or other devices).

Y = the 12-hour average of the measured volumetric oxygen concentration.

(2) Record at least once each successive 5-minute period all measurements obtained from the continuous monitoring devices installed under paragraph (b)(1) of this section. Calculate 3-hour block averages from the recorded measurements of incinerator temperature. Temperature measurements recorded when no TRS emissions are fired in the incinerator (e.g., during incinerator warm-up and cool-down periods when no TRS emissions are generated or an alternative control device is used) may be omitted from the block average calculation.

(3) Record at least once each successive 15-minute period all measurements obtained from the continuous monitoring devices installed under paragraph (b)(2) through (4) of this section and reduce the data as follows:

(i) Calculate 12-hour block averages from the recorded measurements of wet scrubber pressure drop (or smelt dissolving tank scrubber fan amperage)

and liquid flow rate (or liquid supply pressure), as applicable.

(ii) Calculate semiannual averages from the recorded measurements of ESP parameters (secondary voltage and secondary current, or total secondary power) for ESP-controlled recovery furnaces or lime kilns that measure opacity in addition to ESP parameters.

(iii) Calculate 12-hour block averages from the recorded measurements of ESP parameters (secondary voltage and secondary current, or total secondary power) for recovery furnaces or lime kilns with combination ESP/wet scrubber controls.

(4) During the initial performance test required in § 60.285a, the owner or operator must establish site-specific operating limits for the monitoring parameters in paragraphs (b)(2) through (4) of this section by continuously monitoring the parameters and determining the arithmetic average value of each parameter during the performance test. The arithmetic average of the measured values for the three test runs establishes your minimum site-specific operating limit for each wet scrubber or ESP parameter. Multiple performance tests may be conducted to establish a range of parameter values. The owner or operator may establish replacement operating limits for the monitoring parameters during subsequent performance tests using the test methods in § 60.285a.

(5) You must operate the continuous monitoring systems required in paragraphs (a) and (b) of this section to collect data at all required intervals at all times the affected facility is operating except for periods of monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments.

(6) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating limits. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(7) 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.

(d) Excess emissions are defined for this subpart as follows:

(1) For emissions from any recovery furnace, periods of excess emissions are:

(i) All 12-hour averages of TRS concentrations above 5 ppm by volume at 8-percent oxygen for straight kraft recovery furnaces and above 25 ppm by volume at 8-percent oxygen for cross recovery furnaces during times when BLS is fired.

(ii) All 6-minute average opacities that exceed 20 percent during times when BLS is fired.

(2) For emissions from any lime kiln, periods of excess emissions are:

(i) All 12-hour average TRS concentrations above 8 ppm by volume at 10-percent oxygen during times when lime mud is fired.

(ii) All 6-minute average opacities that exceed 20 percent during times when lime mud is fired.

(3) For emissions from any digester system, brown stock washer system, multiple-effect evaporator system, or condensate stripper system, periods of excess emissions are:

(i) All 12-hour average TRS concentrations above 5 ppm by volume at 10-percent oxygen unless the provisions of § 60.283a(a)(1)(i), (ii), or (iv) apply; or

(ii) All 3-hour block averages during which the combustion temperature at the point of incineration is less than 650 °C (1200 °F), where the provisions of § 60.283a(a)(1)(iii) apply and an incinerator is used as the combustion device.

(iii) All times when gases are not routed through the closed-vent system to one of the control devices specified in § 60.283a(a)(1)(i) through (iii) and (v).

(4) For any recovery furnace, lime kiln, or smelt dissolving tank controlled with a wet scrubber emission control device that complies with the parameter monitoring requirements specified in § 60.284a(b)(2), periods of excess emissions are:

(i) All 12-hour block average scrubbing liquid flow rate (or scrubbing liquid supply pressure) measurements below the minimum site-specific limit established during performance testing during times when BLS or lime mud is fired (as applicable), and

(ii) All 12-hour block average scrubber pressure drop (or fan amperage, if used as an alternative under paragraph (b)(2)(iii) of this section) measurements below the minimum site-specific limit established during performance testing during times when BLS or lime mud is fired (as applicable), except during startup and shutdown.

(5) For any recovery furnace or lime kiln controlled with an ESP followed by a wet scrubber that complies with the parameter monitoring requirements specified in § 60.284a(b)(4), periods of excess emissions are:

(i) All 12-hour block average scrubbing liquid flow rate (or scrubbing liquid supply pressure) measurements below the minimum site-specific limit established during performance testing during times when BLS or lime mud is fired (as applicable), and

(ii) All 12-hour block average scrubber pressure drop measurements below the minimum site-specific limit established during performance testing during times when BLS or lime mud is fired (as applicable) except during startup and shutdown,

(iii) All 12-hour block average ESP secondary voltage measurements below the minimum site-specific limit established during performance testing during times when BLS or lime mud is fired (as applicable) including startup and shutdown.

(iv) All 12-hour block average ESP secondary current measurements (or total secondary power values) below the minimum site-specific limit established during performance testing during times when BLS or lime mud is fired (as applicable) except during startup and shutdown.

(e) The Administrator will not consider periods of excess emissions reported under § 60.288a(a) to be indicative of a violation of the standards provided the criteria in paragraphs (e)(1) and (2) of this section are met.

(1) The percent of the total number of possible contiguous periods of excess emissions in the semiannual reporting period does not exceed:

(i) One percent for TRS emissions from straight recovery furnaces, provided that the 12-hour average TRS concentration does not exceed 30 ppm corrected to 8-percent oxygen.

(ii) Two percent for average opacities from recovery furnaces, provided that the ESP secondary voltage and secondary current (or total secondary power) averaged over the semiannual period remained above the minimum operating limits established during the performance test.

(iii) One percent for TRS emissions from lime kilns, provided that the 12-hour average TRS concentration does not exceed 22 ppm corrected to 10-percent oxygen.

(iv) One percent for average opacities from lime kilns, provided that the ESP secondary voltage and secondary current (or total secondary power)

averaged over the semiannual period remained above the minimum operating limits established during the performance test.

(v) One percent for TRS emissions from cross recovery furnaces, provided that the 12-hour average TRS concentration does not exceed 50 ppm corrected to 8-percent oxygen.

(vi) For closed-vent systems delivering gases to one of the control devices specified in § 60.283a(a)(1)(i) through (iii) and (v), the time of excess emissions divided by the total process operating time in the semiannual reporting period does not exceed:

(A) One percent for LVHC closed-vent systems; or

(B) Four percent for HVLC closed-vent systems or for HVLC and LVHC closed-vent systems combined.

(2) The Administrator determines that the affected facility, including air pollution control equipment, is maintained and operated in a manner which is consistent with good air pollution control practice for minimizing emissions during periods of excess emissions.

(3) The 12-hour average TRS concentration uncorrected for oxygen may be considered when determining compliance with the excess emission provisions in paragraphs (e)(1)(i) and (iii) of this section during periods of startup or shutdown when the 12-hour average stack oxygen percentage approaches ambient conditions. If the 12-hour average TRS concentration uncorrected for oxygen is less than the applicable limit (5 ppm for recovery furnaces or 8 ppm for lime kilns) during periods of startup or shutdown when the 12-hour average stack oxygen concentration is 15 percent or greater, then the Administrator will consider the TRS average to be in compliance. This provision only applies during periods of affected facility startup and shutdown.

(f) The procedures under § 60.13 must be followed for installation, evaluation, and operation of the continuous monitoring systems required under this section. All continuous monitoring systems must be operated in accordance with the applicable procedures under Performance Specifications 1, 3, and 5 of appendix B of this part.

§ 60.285a Test methods and procedures.

(a) In conducting the performance tests required by this subpart and § 60.8, the owner or operator must use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures in this section, except as provided in § 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section. Section 60.8(c) must be read as follows for purposes of this subpart: Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown and malfunction shall not constitute representative conditions for the purpose of a performance test.

(b) The owner or operator must determine compliance with the filterable particulate matter standards in § 60.282a(a)(1), (2), (5) and (6) as follows:

(1) Method 5 of Appendix A–3 of this part must be used to determine the filterable particulate matter concentration. The sampling time and sample volume for each run must be at least 60 minutes and 0.90 dscm (31.8 dscf). Water must be used as the cleanup solvent instead of acetone in the sample recovery procedure. The particulate concentration must be corrected to the appropriate oxygen concentration according to § 60.284a(c)(3).

(2) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of Appendix A–2 of this part must be used to determine the oxygen concentration. The gas sample must be taken at the same time and at the same traverse points as the particulate sample.

(3) Method 9 of Appendix A–4 of this part and the procedures in § 60.11 must be used to determine opacity. Opacity measurement is not required for recovery furnaces or lime kilns operating with a wet scrubber alone or a wet scrubber in combination with an ESP.

(4) In addition to the initial performance test required by this subpart and § 60.8(a), you must conduct repeat performance tests for filterable particulate matter at intervals no longer than 5 years following the previous performance test using the procedures in paragraphs (b)(1) and (2) of this section.

(5) When the initial and repeat performance tests are conducted for filterable particulate matter, the owner or operator must also measure condensable particulate matter using Method 202 of Appendix M of 40 CFR part 51.

(c) The owner or operator must determine compliance with the filterable particular matter standards in § 60.282a(a)(3) and (4) as follows:

(1) The emission rate (E) of filterable particulate matter must be computed for each run using the following equation:

$$E = c_s Q_{sd}/BLS$$

Where:

E = emission rate of filterable particulate matter, g/kg (lb/ton) of BLS.

c_s = Concentration of filterable particulate matter, g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dry standard cubic meter per hour (dscm/hr) (dry standard cubic feet per hour (dscf/hr)).

BLS = black liquor solids (dry weight) feed rate, kg/hr (ton/hr).

(2) Method 5 of Appendix A–3 of this part must be used to determine the filterable particulate matter concentration (c_s) and the volumetric flow rate (Q_{sd}) of the effluent gas. The sampling time and sample volume must be at least 60 minutes and 0.90 dscm (31.8 dscf). Water must be used instead of acetone in the sample recovery.

(3) Process data must be used to determine the black liquor solids (BLS) feed rate on a dry weight basis.

(4) In addition to the initial performance test required by this subpart and § 60.8(a), you must conduct repeat performance tests for filterable particulate matter at intervals no longer than 5 years following the previous performance test using the procedures in paragraphs (c)(1) through (3) of this section.

(5) When the initial and repeat performance tests are conducted for filterable particulate matter, the owner or operator must also measure condensable particulate matter using Method 202 of Appendix M of 40 CFR part 51.

(d) The owner or operator must determine compliance with the TRS standards in § 60.283a, except § 60.283a(a)(1)(vi) and (4), as follows:

(1) Method 16 of Appendix A–6 of this part must be used to determine the TRS concentration. The TRS concentration must be corrected to the appropriate oxygen concentration using the procedure in § 60.284a(c)(3). The sampling time must be at least 3 hours, but no longer than 6 hours.

(2) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of Appendix A–2 of this part must be used to determine the oxygen concentration. The sample must be taken over the same time period as the TRS samples.

(3) When determining whether a furnace is a straight kraft recovery furnace or a cross recovery furnace, TAPPI Method T 624 (incorporated by reference—see § 60.17) must be used to determine sodium sulfide, sodium

hydroxide, and sodium carbonate. These determinations must be made 3 times daily from the green liquor, and the daily average values must be converted to sodium oxide (Na_2O) and substituted into the following equation to determine the green liquor sulfidity:

$$GLS=100C_{Na_2S}/(C_{Na_2S}C_{NaOH}C_{Na_2CO_3})$$

Where:

GLS = green liquor sulfidity, percent.
C_{Na_2S} = concentration of Na_2S as Na_2O, milligrams per liter (mg/L) (grains per gallon (gr/gal)).
C_{NaOH} = concentration of NaOH as Na_2O, mg/L (gr/gal).
$C_{Na_2CO_3}$ = concentration of Na_2CO_3 as Na_2O, mg/L (gr/gal).

(4) For recovery furnaces and lime kilns, in addition to the initial performance test required in this subpart and § 60.8(a), you must conduct repeat TRS performance tests at intervals no longer than 5 years following the previous performance test using the procedures in paragraphs (d)(1) and (2) of this section.

(e) The owner or operator must determine compliance with the TRS standards in § 60.283a(a)(1)(vi) and (4) as follows:

(1) The emission rate (E) of TRS must be computed for each run using the following equation:

$$E=C_{TRS}\ F\ Q_{sd}/P$$

Where:

E = emission rate of TRS, g/kg (lb/ton) of BLS or ADP.
CTRS = average combined concentration of TRS, ppm.
F = conversion factor, 0.001417 g H_2S/cubic meter (m^3)-ppm (8.846×10^{-8} lb H_2S/cubic foot (ft^3)-ppm).
Q_{sd} = volumetric flow rate of stack gas, dscm/hr (dscf/hr).
P = black liquor solids feed or pulp production rate, kg/hr (ton/hr).

(2) Method 16 of Appendix A–6 of this part must be used to determine the TRS concentration (C_{TRS}).

(3) Method 2 of Appendix A–1 of this part must be used to determine the volumetric flow rate (Q_{sd}) of the effluent gas.

(4) Process data must be used to determine the black liquor feed rate or the pulp production rate (P).

(5) For smelt dissolving tanks, in addition to the initial performance test required in this subpart and § 60.8(a), you must conduct repeat TRS performance tests at intervals no longer than 5 years following the previous performance test using the procedures in paragraphs (e)(1) through (4) of this section.

(f) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) In place of Method 5 of Appendix A–3 of this part, Method 17 of Appendix A–6 of this part may be used if a constant value of 0.009 g/dscm (0.004 gr/dscf) is added to the results of Method 17 and the stack temperature is no greater than 204°C (400 °F).

(2) In place of Method 16 of Appendix A–6 of this part, Method 16A, 16B, or 16C of Appendix A–6 of this part may be used.

(3) In place of Method 3B of Appendix A–2 of this part, ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) may be used.

§ 60.286a Affirmative Defense for Violations of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in §§ 60.282a and 60.283a, 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 if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense must 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 emission 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 must 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 must submit a written report to the Administrator with all necessary supporting documentation that explains how it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report must 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.

§ 60.287a Recordkeeping.

(a) The owner or operator must maintain records of the performance evaluations of the continuous monitoring systems.

(b) For each continuous monitoring system, the owner or operator must maintain records of the following information, as applicable:

(1) Records of the opacity of the gases discharged into the atmosphere from any recovery furnace or lime kiln using an ESP emission control device, except as specified in paragraph (b)(6) of this section, and records of the ESP secondary voltage and secondary current (or total secondary power) averaged over the reporting period for the opacity allowances specified in § 60.284a(e)(1)(ii) and (iv).

(2) Records of the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from any lime kiln, recovery furnace, digester system, brown stock washer system, multiple-effect evaporator system, or condensate stripper system, except where the provisions of § 60.283a(a)(1)(iii) or (iv) apply.

(3) Records of the incinerator combustion temperature at the point of incineration of effluent gases which are emitted from any digester system, brown stock washer system, multiple effect evaporator system, or condensate stripper system where the provisions of § 60.283a(a)(1)(iii) apply and an incinerator is used as the combustion device.

(4) For any recovery furnace, lime kiln, or smelt dissolving tank using a wet scrubber emission control device:

(i) Records of the pressure drop of the gas stream through the control equipment (or smelt dissolving tank scrubber fan amperage), and

(ii) Records of the scrubbing liquid flow rate (or scrubbing liquid supply pressure).

(5) For any recovery furnace or lime kiln using an ESP control device:

(i) Records of the secondary voltage of each ESP collection field, and

(ii) Records of the secondary current of each ESP collection field, and

(iii) If used as an alternative to secondary voltage and current, records of the total secondary power of each ESP collection field.

(6) For any recovery furnace or lime kiln using an ESP followed by a wet scrubber, the records specified under paragraphs (b)(4) and (5) of this section.

(7) Records of excess emissions as defined in § 60.284a(d).

(c) For each malfunction, the owner or operator must maintain records of the following information:

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

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

§ 60.288a Reporting.

(a) For the purpose of reports required under § 60.7(c), any owner or operator subject to the provisions of this subpart must report semiannually periods of excess emissions defined in § 60.284a(d).

(b) Within 60 days after the date of completing each performance test (defined in § 60.8) 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 as follows. You must use the latest version of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*) existing at the time of the performance test to generate a submission package file, which documents performance test data. You must then submit the file generated by the ERT through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed by logging in to the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). Only data collected using test methods supported by the ERT as listed on the ERT Web site are subject to the requirement to submit the performance test data electronically. 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 (b). 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, the owner or operator must submit the results of the performance test to the Administrator at the appropriate address listed in § 60.4.

(c) Within 60 days after the date of completing each CEMS performance evaluation test as defined in § 60.13, you must submit relative accuracy test audit (RATA) data to the EPA's Central Data Exchange (CDX) by using CEDRI in accordance with paragraph (b) 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 § 60.4.

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

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

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

[FR Doc. 2014–06719 Filed 4–3–14; 8:45 am]
BILLING CODE 6560–50–P

FEDERAL REGISTER

Vol. 79 Thursday,
No. 39 February 27, 2014

Part III

Environmental Protection Agency

40 CFR Parts 51, 60, 61, et al.
Revisions to Test Methods and Testing Regulations; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 60, 61, and 63

[EPA–HQ–OAR–2010–0114; FRL–9906–23–OAR]

RIN 2060–AQ01

Revisions to Test Methods and Testing Regulations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action promulgates technical and editorial corrections for source testing of emissions and operations. Some current testing provisions contain inaccuracies and outdated procedures, and new alternatives that have been approved are being added. These revisions will improve the quality of data and will give testers additional flexibility to use the newly approved alternative procedures.

DATES: This final rule is effective on February 27, 2014. The incorporation by reference materials listed in the rule are approved by the Director of the Federal Register as of February 27, 2014.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2010–0114. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., confidential business information (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 at *www.regulations.gov* or in hard copy at the Air Docket, EPA/DC, William Jefferson Clinton (WJC) Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC. The Docket Facility and the Public Reading Room are 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. Lula Melton, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Quality Assessment Division, Measurement Technology Group (E143–02), Research Triangle Park, North Carolina 27711; telephone number: (919) 541–2910; fax number: (919) 541–0516; email address: *melton.lula@epa.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. General Information

A. Does this action apply to me?

The revisions promulgated in this final rule apply to testing at a number of source categories. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. Where can I obtain a copy of this action?

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

C. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of this final rule is available by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 28, 2014. Under section 307(d)(7)(B) of the CAA, only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by this action may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

II. Background

The revisions to test methods and testing regulations were proposed in the **Federal Register** on January 9, 2012, with a public comment period that ended March 9, 2012. Thirty-eight comment letters were received from the public. Changes were made to this final rule based on the public comments.

III. Summary of Amendments

A. Appendix M of Part 51

In the introduction of Appendix M of part 51, Methods 3A and 19 are added to the list of methods not requiring the use of audit samples.

B. Method 201A of Appendix M of Part 51

Revisions are made to Method 201A as published on December 21, 2010. Typographical errors in references to acetone blanks, isokinetic sampling rate, source gas temperatures, stack blockage dimensions by the sampling heads, and particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM_{10}) in Sections 7.2.1, 8.3.4(b), 8.3.4.1, 8.7.2.2, and 8.7.5.5(a), respectively, are corrected. An erroneous reference to Methods 4A and 5 in Section 10.1 when using a standard pitot tube is corrected to refer to Methods 1 and 2. Section 10.5, which addresses Class A volumetric glassware is deleted because it is not needed. For those filters that cannot be weighed to a constant weight in Section 11.2.1, instructions are added to flag and report the data as a minimum value. It is noted that the nozzle, front half, and in-stack filter samples need to be speciated into organic and inorganic fractions similar to the practice in Method 17. The method now notes that neither Method 17 nor 201A require a separate analysis of the filter for inorganic and organic particulate matter. Clarity is added for using Method 17 for quantifying condensable particulate matter. An incorrect term in Equation 9 of Section 12.5 is corrected. In the nomenclature in Section 12.1, V_b, the volume of aliquot taken for ion chromatography (IC) analysis, is deleted.

C. Method 202 of Appendix M of Part 51

Revisions are made to Method 202 as published on December 21, 2010. In Sections 7.2.1 and 7.2.2, an error in the units of the acetone blank is corrected. In Section 8.5.3.1, the text erroneously referring to empty impingers is deleted. Section 11.2.1 is clarified concerning the use of Method 17 for quantifying condensable particulate matter. Figures 2 and 3 are revised to correctly show the first impinger with an extended stem instead of a shortened one to be consistent with the method text, and the condensed moisture and sample portion of the sampling train are labeled to make it easy to identify. Figures 4, 5, and 6 are republished because of the poor print quality in the December 21, 2010, publication.

D. General Provisions (Subpart A) Part 60

In the General Provisions of part 60, Section 60.13(d)(1) is revised to remove the phrase "automatically, intrinsic to the opacity monitor." Methods 3A and 19 are added to the list of methods not requiring the use of audit samples in Section 60.8(g). A new Section 60.8(i) is added to allow the use of Method 205 of 40 CFR part 51, Appendix M, "Verification of Gas Dilution Systems for Field Instrument Calibrations," as an alternative provision whenever multiple calibration gases are required under part 60. The agency notes, however, that the use of calibration gas dilution devices continues to be disallowed for part 75 applications (see 40 CFR 75.22(a)(5)(i)). Section 60.17 is revised to arrange the consensus standards that are incorporated by reference in alpha-numeric order.

E. Industrial-Commercial-Institutional Steam Generating Units (Subpart Db) Part 60

In subpart Db, Method 320 is allowed as an alternative for determining nitrogen oxides (NO_X) concentration in Section 60.46b(f)(1)(ii), (h)(1) and (2), and sulfur dioxide (SO_2) concentration in Section 60.47b(b)(2).

F. Hospital/Medical/Infectious Waste Incinerators (Subpart Ec) Part 60

In subpart Ec, the definition of medical/infectious wastes in Section 60.51c is revised to correct the misspelling of "cremation."

G. Sulfuric Acid Plants (Subpart H) Part 60

In subpart H, an equation for calculating the SO_2 emission rate in Section 60.84(d) is corrected.

H. Sewage Treatment Plants (Subpart O) Part 60

In subpart O, a reference to Method 209F in Section 60.154(b)(5) is revised to reflect a newer available version of the method (i.e., 2540G).

I. Kraft Pulp Mills (Subpart BB) Part 60

In subpart BB, a typographical error is corrected in the equation for correcting the total reduced sulfur concentration to 10 percent oxygen.

J. Stationary Gas Turbines (Subpart GG) Part 60

In subpart GG, the definitions of terms for the equation in Section 60.335(b)(l) are revised to allow the reference combustor inlet absolute pressure to be measured in millimeters of mercury (mm Hg). The site barometric pressure is allowed as an alternative to the observed combustor inlet absolute pressure for calculating the mean NO_X emission concentration.

K. Lead-Acid Battery Manufacturing Plants (Subpart KK) Part 60

In subpart KK, Method 29 is allowed as an alternative to Method 12 in Section 60.374(b)(1) and (c)(2) for determining the lead concentration and flow rate of the effluent gas. An error in the equation for calculating the lead emission concentration in 60.374(b)(2) is corrected.

L. Metallic Mineral Processing Plants (Subpart LL) Part 60

In subpart LL, an error in the value of the particulate matter standard in Section 60.382(a)(1) is corrected from 0.02 g/dscm to 0.05 g/dscm. An alternative procedure, wherein a single visible emission observer can conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval, is allowed.

M. Asphalt Processing and Asphalt Roofing Manufacture (Subpart UU) Part 60

In subpart UU, an error in the value of the particulate matter standard for saturated felt or smooth-surfaced roll roofing is corrected from 0.04 kg/Mg to 0.4 kg/Mg.

N. Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations (Subpart NNN) Part 60

In subpart NNN, references to paragraphs in Section 60.660(c)(4) and Section 60.665(h)(2) and (3) are corrected.

O. Stationary Compression Ignition Internal Combustion Engines (Subpart IIII) Part 60

In Subpart IIII, the requirement to use Method 1 or 1A for sampling point selection in testing gaseous emission from engines with smaller ducts is dropped, and single- or three-point sampling, depending on duct size, is added.

P. Stationary Spark Ignition Internal Combustion Engines (Subpart JJJJ) Part 60

In Subpart JJJJ, the requirement to use Method 1 or 1A for sampling point selection in testing gaseous emissions from engines with smaller ducts is dropped, and single- or three-point sampling, depending on duct size, is added.

Q. Method 1 of Appendix A–1 of Part 60

In Method 1, the distances from the sampling point to flow disturbances is clarified in Figure 1–1, and Figure 1–2 is corrected to show the proper demarcation between the requirement for 12 and 16 sampling points.

R. Method 2 of Appendix A–1 of Part 60

In Method 2, a pressure stability specification for the pitot tube leak-check is added. An erroneous reference to Figure 2–6B is corrected to reference Figure 2–7B. An error in a term in the denominator of Equation 2–7 is corrected. The velocity constant in English units used in Equation 2–7 is corrected by changing the units from m/sec to ft/sec. The term for absolute temperature in Equations 2–7 and 2–8 is corrected to represent the average of the absolute temperatures; an inadvertently omitted term is added to Section 12.1 for the average absolute temperature; and calibrating a barometer against a NIST-traceable barometer is allowed as an alternative to calibrating against a mercury barometer.

S. Method 2A of Appendix A–1 of Part 60

In Method 2A, calibrating a barometer against a NIST-traceable barometer is allowed as an alternative to calibrating against a mercury barometer.

T. Method 2B of Appendix A–1 of Part 60

In Method 2B, nomenclature errors are corrected and the assumed ambient carbon dioxide concentration used in the calculations is changed from 300 to 380 ppm to closer approximate current ambient levels.

U. Method 2D of Appendix A–1 of Part 60

In Method 2D, calibrating a barometer against a NIST-traceable barometer is allowed as an alternative to calibrating against a mercury barometer.

V. Method 3A of Appendix A–2 of Part 60

In Method 3A, a redundant sentence noting that pre-cleaned air may be used for the high-level calibration gas is deleted.

W. Method 3C of Appendix A–2 of Part 60

In Method 3C, an equation for correcting the sample nitrogen concentration for tank dilution is added as a supplemental calculation option for Method 25C samples.

X. Method 4 of Appendix A–3 of Part 60

In Method 4, the English value for the leak rate exceedance in Section 9.1 is corrected from 0.20 cfm to 0.020 cfm. Method 6A, Method 320, and a calculation using F-factors are added as alternatives to Method 4 for the moisture determination.

Y. Method 5 of Appendix A–3 of Part 60

In Method 5, it is clarified that the deionized water used in the analysis of material caught in the impingers must have ≤0.001 percent residue; the factor K is corrected to read K' in Equation 5–13; calibrating a barometer against a NIST-traceable barometer is allowed as an alternative to calibrating against a mercury barometer; calibrating a temperature sensor against a thermometer equivalent to a mercury-in-glass thermometer is allowed as an alternative to calibrating against a mercury-in-glass thermometer; rechecking temperature sensors for the filter holder and metering system after each test is allowed in place of having sensors calibrated within 3 °F; the option to check the probe heater calibration after a test at a single point using a reference thermometer is added; the use of weather station barometric pressure corrected to testing point elevation is added as an option to having an on-site barometer; a single acetone blank per container is allowed in place of a blank from each wash bottle; Section 10.3.3 is clarified as a post-test metering system calibration check rather than a metering system calibration, and an alternative metering check procedure is added; the use of filter holder supports or frits made of Teflon is allowed without having to first obtain the Administrator's approval; and Reference 13 for post-test calibration is added to the method.

Z. Method 5A of Appendix A–3 of Part 60

In Method 5A, mercury-free thermometers are allowed as an alternative to mercury-in-glass thermometers.

AA. Method 5E of Appendix A–3 of Part 60

In Method 5E, the requirement to use the Rosemount Model 2100A total organic content analyzer is replaced with the Tekmar-Dohrmann or equivalent analyzer. In Section 12.5, the equation for total particulate concentration is correctly labeled as Eq. 5E–5.

BB. Method 5H of Appendix A–3 of Part 60

In Method 5H, Section 12.1 is revised to add missing terms C_i, C_o, Q_i, and Q_o; and procedures for the determination of an alternative tracer gas flow rate are added.

CC. Method 6 of Appendix A–4 of Part 60

In Method 6, calibrating a temperature sensor against a thermometer equivalent to a mercury-in-glass thermometer is allowed as an alternative to using a mercury-in-glass thermometer, and calibrating a barometer against a NIST-traceable barometer is allowed as an alternative to calibrating against a mercury barometer.

DD. Method 6C of Appendix A–4 of Part 60

In Section 4.0 of Method 6C, an incorrect reference to Section 4.1 of Method 6 is corrected to reference Section 4.0 of Method 7E. Provisions that were removed from the original method that addressed potential quenching effects in fluorescence analyzers are added to the method.

EE. Method 7 of Appendix A–4 of Part 60

In Method 7, procedures are added to avoid biasing the results when sampling under conditions of high SO_2 concentrations; calibrating a barometer against a NIST-traceable barometer is added as an alternative to calibrating against a mercury barometer; and calibrating a temperature sensor against a thermometer equivalent to a mercury-in-glass thermometer is an acceptable alternative to using a mercury-in-glass thermometer.

FF. Method 7A of Appendix A–4 of Part 60

In Method 7A, new procedures are added to avoid biasing the results when sampling under conditions of high SO_2 concentrations, and calibrating a temperature sensor against a thermometer equivalent to a mercury-in-glass thermometer is added as an acceptable alternative to using a mercury-in-glass thermometer.

GG. Method 7E of Appendix A–4 of Part 60

In Method 7E, the instructions for choosing the high-level calibration gas are clarified. Instructions are added to minimize contact of the sample with any condensate to reduce the chance of sample loss, and an error in the traverse point locations used to determine stratification across large stacks is corrected. The basis of a stable response for measurements in the system response time determination is revised in Section 8.2.5 to conform with Section 8.2.6. Alternative sampling bags made of materials other than Tedlar are allowed if the materials are applicable for retaining the compounds of interest.

HH. Method 8 of Appendix A–4 of Part 60

In Method 8, an error in the definition of V_{soln} is corrected. Figure 8–1 is clarified to identify which impingers collect sulfuric acid/sulfur trioxide and which collect SO_2.

II. Method 10 of Appendix A–4 of Part 60

Method 10 is revised to allow the use of sample tanks as an alternative to flexible bags for sample collection.

JJ. Methods 10A and 10B of Appendix A–4 of Part 60

In Methods 10A and 10B, sampling bags made of materials other than Tedlar are allowed if the materials have the sample retaining qualities of Tedlar.

KK. Method 11 of Appendix A–5 of Part 60

Method 11 is revised to address sample breakthrough at high concentrations by using an additional collection impinger. Calibrating a temperature sensor against a thermometer equivalent to a mercury-in-glass thermometer is an acceptable alternative to using a mercury-in-glass thermometer.

LL. Method 12 of Appendix A–5 of Part 60

Method 12 is revised to allow for analysis by inductively coupled plasma-atomic emission spectrometry (ICP–AES) and cold vapor atomic fluorescence spectrometry (CVAFS) as alternatives to atomic absorption (AA) analysis.

MM. Method 14A of Appendix A–5 of Part 60

In Section 10.1.1 of Method 14A, an incorrect reference to Figure 5–6 is corrected to reference Figure 5–5.

NN. Method 16A of Appendix A–6 of Part 60

In Method 16A, the applicability section notes that method results may be biased low if used at sources other than kraft pulp mills where stack oxygen levels may be lower.

OO. Method 16C of Appendix A–6 of Part 60

In Method 16C, errors in the nomenclature and the equation for calculating the total reduced sulfur concentration are corrected.

PP. Method 18 of Appendix A–6 of Part 60

In Method 18, sampling bags made of materials other than Tedlar are allowed if the materials are applicable for retaining the compounds of interest.

QQ. Method 23 of Appendix A–7 of Part 60

In Method 23, the requirement in Section 2.2.7 that silica gel be stored in metal containers has been deleted. Section 4.2.7 is clarified to note that the used silica gel should be transferred to its original container or other suitable vessel if moisture is being determined or discarded if not needed. Mercury-free thermometers are allowed as alternatives to mercury-in-glass thermometers. Section 8.0, which was inadvertently removed in a previous rulemaking, has been added.

RR. Method 24 of Appendix A–7 of Part 60

In Method 24, ASTM Method D2369 is cited without referencing specific sections to preclude confusion if the method sections are revised in the future.

SS. Method 25 of Appendix A–7 of Part 60

In Method 25, more detailed information is given to describe the filters used for sample collection.

TT. Method 25C of Appendix A–7 of Part 60

Method 25C is revised to allow sampling lines made of Teflon. Probes that have closed points and are driven below the surface in a single step and withdrawn a distance to create a gas gap are allowed as acceptable substitutes to pilot probes and the auger procedure.

UU. Method 25D of Appendix A–7 of Part 60

In Method 25D, errors in cross-references within the method are corrected.

VV. Method 26 of Appendix A–8 of Part 60

Method 26 is revised to allow the use of heated Teflon probes in place of glass-lined probes. Conflicting temperature requirements for the sampling system are clarified, and the note to keep the probe and filter temperature at least 20 °C above the source temperature is removed. The location of the thermocouple that monitors the collected gas temperature is clarified as being as close to the filter holder as practicable instead of in the gas stream. Method 26A is allowed as an acceptable alternative when Method 26 is required.

WW. Method 26A of Appendix A–8 of Part 60

Method 26A is revised to clearly state that the temperature of the probe and filter must be maintained between 120 and 134 °C.

XX. Method 29 of Appendix A–8 of Part 60

Method 29 is revised to allow sample analysis by CVAFS as an alternative to AA analysis.

YY. Method 30B of Appendix A–8 of Part 60

In Method 30B, calibrating a barometer against a NIST-traceable barometer is allowed as an alternative to calibrating against a mercury barometer. Table 9–1 and the method text are revised to amend the quality assurance/quality control criteria for sorbent trap section 2 breakthrough and sample analysis to address compliance testing and relative accuracy testing of mercury monitoring systems currently being conducted at much lower emission concentrations. The method is revised to include the most up-to-date citation for determining the method detection limit.

ZZ. Performance Specification 3 of Appendix B of Part 60

In Performance Specification 3, a statement that was inadvertently removed that allows the relative accuracy to be within 20 percent of the reference method mean value is added to establish the original intent of the rule.

AAA. Performance Specification 4 of Appendix B of Part 60

Performance Specification 4 is revised to remove the interference trap specified in Method 10 when evaluating non-dispersive infrared continuous emission monitoring systems against Method 10.

BBB. Performance Specification 4B of Appendix B of Part 60

Performance Specification 4B is clarified to note that Equation 1 in Section 7.1.1 for calculating calibration error only applies to the carbon monoxide monitor and not the oxygen monitor. It is noted for the oxygen monitor that the calibration error should be expressed as the oxygen concentration difference between the mean monitor and reference value at three levels.

CCC. Performance Specification 7 of Appendix B of Part 60

Performance Specification 7 is revised to allow Methods 15 and 16 as reference methods in addition to Method 11.

DDD. Performance Specification 11 of Appendix B of Part 60

In Performance Specification 11, errors in the denominators of Equations 11–1 and 11–2 are corrected.

EEE. Performance Specification 12B of Appendix B of Part 60

In Performance Specification 12B, allowance is made for using a single good trap when one is lost, broken or damaged. More flexibility is also allowed in meeting the stack flow-to-sample flow ratio.

FFF. Performance Specification 15 of Appendix B of Part 60

In Performance Specification 15, the general references to 40 CFR part 60, Appendix B, for the relative accuracy analysis procedure are revised to specifically cite Performance Specification 2 of 40 CFR part 60, Appendix B.

GGG. Performance Specification 16 of Appendix B of Part 60

Performance Specification 16 is revised to clarify the retesting of a predictive emission monitoring system (PEMS) after a sensor is replaced. Relative accuracy testing at three load or production rate levels is allowed in cases where the key operating parameter is not readily alterable. Additional instruction is added for performing the relative accuracy audit (RAA). An error in the RAA acceptance criterion is corrected, and an alternative acceptance criterion for low concentration measurements is added. The yearly relative accuracy test audit clearly notes that the statistical tests in Section 8.3 are not required for this test. An incorrect reference to Equation 16–4 in Section 12.4 is corrected.

HHH. Procedure 1 of Appendix F of Part 60

In Procedure 1, the relevant performance specification would be cited for the RAA calculation instead of using the current Equation 1–1, which is not appropriate for all pollutants.

III. Procedure 2 of Appendix F of Part 60

In Procedure 2, Equations 2–2 and 2–3 are revised to have the full-scale value in the denominator, which is more appropriate than the up-scale check value. The denominator of equation 2–4 is revised to include the volume of the reference device rather than the full-scale value.

JJJ. Procedure 5 of Appendix F of Part 60

In Procedure 5, the second section listed as Section 6.2.6 is correctly numbered as Section 6.2.7.

KKK. General Provisions (Subpart A) Part 61

In the General Provisions of part 61, Methods 3A and 19 are added to the list of methods not requiring the use of audit samples in Section 61.13(e).

LLL. Beryllium (Subpart C) Part 61

In the Beryllium National Emission Standards for Hazardous Air Pollutants (NESHAP), Method 29 of part 60 is added as an acceptable alternative to Method 104 in Section 61.33(a) for emissions testing.

MMM. Beryllium Rocket Motor Firing (Subpart D) Part 61

In the beryllium rocket motor firing NESHAP, a conversion error in the emission standard in Section 61.42(a) is corrected.

NNN. Mercury (Subpart E) Part 61

In the mercury NESHAP, Method 29 of part 60 is added as an acceptable alternative to Method 101A in Section 61.53(d)(2) for emissions testing.

OOO. Inorganic Arsenic Emissions From Glass Manufacturing Plants (Subpart N) Part 61

In the glass manufacturing plants NESHAP, Method 29 in Appendix A of part 60 is added as an acceptable alternative to Method 108 in Section 61.164(d)(2)(i) for determining the arsenic emissions rate and in Section 61.164(e)(1)(i) and (e)(2) for determining

the arsenic concentration in a gas stream.

PPP. Method 101 of Appendix B of Part 61

Method 101 is revised to allow analysis by ICP–AES or CVAFS as alternatives to AA analysis.

QQQ. Method 101A of Appendix B of Part 61

Method 101A is revised to allow analysis by ICP–AES or CVAFS as alternatives to AA analysis.

RRR. Method 102 of Appendix B of Part 61

In Method 102, mercury-free thermometers are allowed in place of mercury-in-glass thermometers.

SSS. Method 104 of Appendix B of Part 61

Method 104 is revised to allow analysis by ICP–AES and CVAFS as alternatives to AA analysis. A new alternative procedures section is added to address ICP–AES.

TTT. Methods 108 and 108A of Appendix B of Part 61

Methods 108 and 108A are revised to allow analysis by ICP–AES as an alternative to AA analysis. A new alternative procedures section is added to address ICP–AES.

UUU. General Provisions (Subpart A) Part 63

In the General Provisions of part 63, Methods 3A and 19 are added to the list of methods not requiring the use of audit samples in Section 63.7(c). In Section 63.8(f)(6)(iii), an incorrect reference to a section of Performance Specification 2 is corrected. Section 63.14 is revised to arrange the materials that are incorporated by reference in alpha-numeric order.

VVV. Synthetic Organic Chemical Manufacturing Industry (Subpart G) Part 63

Subpart G is revised to allow the use of Method 316 or Method 8260B in the SW–846 Compendium of Methods to determine hazardous air pollutant concentrations in wastewater streams in Section 63.144(b)(5)(i).

WWW. Chromium Emissions From Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks (Subpart N) Part 63

South Coast Air Quality Management District Method 205.1 is added as a testing option for measuring total chromium.

XXX. Ethylene Oxide Emissions Standards for Sterilization Facilities (Subpart O) Part 63

The ethylene oxide emissions standard for sterilization facilities is revised to allow California Air Resources Board (CARB) Method 431 as an alternative to the procedures in Section 63.365(b) for determining the efficiency at the sterilization chamber vent. An error in a reference to a section in Performance Specification 8 is also corrected.

YYY. Marine Tank Vessel Loading Operations (Subpart Y) Part 63

The marine tank vessel loading operations emissions standard is revised to allow Method 25B as an alternative to Method 25A in Section 63.565(d)(5) for determining the average VOC concentration upstream and downstream of recovery devices. Method 25B is allowed as an alternative to Methods 25 and 25A for determining the percent reduction in VOC in Section 63.565(d)(8), and the requirement that Method 25B be validated according to Method 301 in Section 63.565(d)(10) is added. Method 25B is also added as an alternative to Method 25A in determining the baseline outlet VOC concentration in Section 63.565(g).

ZZZ. Aerospace Manufacturing and Rework Facilities (Subpart GG) Part 63

The aerospace manufacturing and rework facilities emissions standard is revised to remove an incorrect reference to the location of Method 319 in Section 63.750(o).

AAAA. Pharmaceuticals Production (Subpart GGG) Part 63

The pharmaceuticals production emissions standard is revised to allow Method 320 as an alternative to Method 18 for demonstrating that a vent is not a process vent.

BBBB. Secondary Aluminum Production (Subpart RRR) Part 63

The secondary aluminum production emissions standard is revised to allow Method 26 as an alternative to Method 26A in Section 63.1511(c)(9) for determining hydrochloric acid (HCl) concentration.

CCCC. Manufacturing of Nutritional Yeast (Subpart CCCC) Part 63

Table 2 in the manufacturing of nutritional yeast emissions standard is revised to delete the requirement to use Methods 1, 2, 3, and 4 when measuring VOC by Method 25A.

DDDD. Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (Subpart UUUU) Part 63

Table 4 in the petroleum refineries emissions standard is revised to allow Method 320 as an alternative to Method 18 for determining control device efficiency for organic compounds.

EEEE. Stationary Reciprocating Internal Combustion Engines (Subpart ZZZZ) Part 63

Table 4 in the stationary reciprocating internal combustion engines emissions standard is revised to clarify that a heated probe is not necessary when using ASTM D6522 to measure oxygen or carbon dioxide concentrations. The requirement to use Method 1 or 1A for sampling site and sampling point selection in testing gaseous emissions from engines with smaller ducts is deleted, and single- or three-point sampling, depending on duct size, is added.

FFFF. Method 306 of Appendix A of Part 63

Method 306 is revised to remove references to two figures that do not exist and to clarify the conditions under which ICP is appropriate for sample analysis. Alternative mercury-free thermometers are allowed as alternatives to mercury-in-glass thermometers.

GGGG. Method 306A of Appendix A of Part 63

In Method 306A, information is added to clarify the conditions under which sample filtering is required.

HHHH. Methods 308, 315, and 316 of Appendix A of Part 63

In Methods 308, 315, and 316, calibrating a temperature sensor against a thermometer equivalent to a mercury-in-glass thermometer is added as an alternative to mercury-in-glass thermometers. Alternative mercury-free thermometers are allowed as alternatives to mercury-in-glass thermometers.

IIII. Method 321 of Appendix A of Part 63

In Method 321, the term for dilution factor in the calculations is clarified.

IV. Public Comments on the Proposed Amendments

Thirty-eight comment letters were received on the proposed rule. The public comments and the agency's responses are summarized in the Summary of Comments and Responses Document that has been added to the

docket that is accessible at the address given in the **ADDRESSES** section of this preamble.

V. Statutory and Executive Order Reviews

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

This action is not a "significant regulatory action" under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is, therefore, not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). It does not involve the expenditure of $100 million in a year and does not raise significant issues. This final rule amends current testing regulations by removing errors and obsolete provisions and adding approved alternative procedures.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* Burden is defined at 5 CFR 1320.3(b). This final rule does not add information collection requirements beyond those currently required under the applicable regulations. This final rule amends current testing regulations by removing errors and obsolete provisions and adding approved alternative procedures.

C. Regulatory Flexibility Act

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

For purposes of assessing the impacts of this rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This final rule will not impose any requirements on small entities since it only corrects and updates current requirements and adds new testing options.

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 action imposes no enforceable duty on any state, local or tribal governments or the private sector. Therefore, this action is not subject to the requirements of sections 202 or 205 of the UMRA. 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. The alternative procedure being added will give small entities more flexibility in choosing testing procedures in applicable situations.

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 corrects and updates current testing requirements. 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). This final rule corrects and updates testing provisions that are already currently mandated. It does not add any new requirements and does not affect pollutant emissions or air quality. 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 EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

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

This rule is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, 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. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable voluntary consensus standards. This action does not involve technical standards. Therefore, the EPA did not consider the use of any voluntary consensus standards.

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

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

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. This final rule does not relax the control measures on sources regulated by the rule and,

therefore, will not cause emissions increases from these sources.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register.** A major rule cannot take effect until 60 days after it is published in the **Federal Register.** This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective on February 27, 2014.

List of Subjects

40 CFR Parts 51 and 61

Air pollution control, Environmental protection, Performance specifications, and Test methods and procedures.

40 CFR Parts 60 and 63

Air pollution control, Environmental protection, Incorporation by reference, Performance specifications, and Test methods and procedures.

Dated: January 28, 2014.

Gina McCarthy,

Administrator.

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

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 51 continues to read as follows:

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

■ 2. Amend appendix M to part 51 as follows:
■ a. By revising section 4.0.a.
■ b. By amending Method 201A as follows:
■ i. By revising section 7.2.1.
■ ii. By revising paragraph 8.3.4(b).
■ iii. By revising section 8.3.4.1.
■ iv. By revising section 8.7.2.2.
■ v. By revising paragraph 8.7.5.5(a).
■ vi. By revising the introductory text of section 10.1.
■ vii. By removing section 10.5.
■ viii. By revising section 11.2.1.
■ ix. By removing the term "Vb" and its definition from section 12.1.
■ x. By revising Equations 8 and 9 in section 12.5.
■ c. By amending Method 202 as follows:
■ i. By revising sections 7.2.1 and 7.2.2.
■ ii. By revising section 8.5.1.
■ iii. By revising section 8.5.3.1.
■ iv. By revising sections 11.2.1 and 11.2.2.
■ vi. By revising Figures 2, 3, 4, 5, and 6 in section 18.0.

Appendix M to Part 51—Recommended Test Methods for State Implementation Plans

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4.0. * * *

a. The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A–3 of part 60, Methods 6C, 7E, 9, and 10 of appendix A–4 of part 60, Methods 18 and 19 of appendix A–6 of part 60, Methods 20, 22, and 25A of appendix A–7 of part 60, and Methods 303, 318, 320, and 321 of appendix A of part 63 of this chapter. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, *http://www.epa.gov/ttn/emc,* to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field, and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request and the compliance authority may grant a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and then report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

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Method 201A—Determination of PM_{10} and $PM_{2.5}$ Emissions From Stationary Sources (Constant Sampling Rate Procedure)

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7.2.1 Acetone. Use acetone that is stored in a glass bottle. Do not use acetone from a metal container because it will likely produce a high residue in the laboratory and field reagent blanks. You must use acetone with blank values less than 1 part per million by weight residue. Analyze acetone blanks prior to field use to confirm low blank values. In no case shall a blank value of greater than 0.0001 percent (1 part per million by weight) of the weight of acetone used in sample recovery be subtracted from the sample weight (*i.e.*, the maximum blank correction is 0.1 mg per 100 g of acetone used to recover samples).

* * * * *

8.3.4 * * *

(b) The appropriate nozzle to maintain the required gas sampling rate for the velocity pressure range and isokinetic range. If the isokinetic range cannot be met (e.g., batch processes, extreme process flow or temperature variation), void the sample or use methods subject to the approval of the Administrator to correct the data. The acceptable variation from isokinetic sampling is 80 to 120 percent and no more than 100 ± 21 percent (2 out of 12 or 5 out of 24) sampling points outside of this criteria.

* * * * *

8.3.4.1 Preliminary traverse. You must use an S-type pitot tube with a conventional thermocouple to conduct the traverse. Conduct the preliminary traverse as close as possible to the anticipated testing time on sources that are subject to hour-by-hour gas flow rate variations of approximately ± 20 percent and/or gas temperature variations of approximately ± 28 °C (± 50 °F). (Note: You should be aware that these variations can cause errors in the cyclone cut diameters and the isokinetic sampling velocities.)

* * * * *

8.7.2.2 Probe blockage factor. You must use Equation 26 to calculate an average probe blockage correction factor (b_f) if the diameter

of your stack or duct is between 25.7 and 36.4 inches for the combined $PM_{2.5}/PM_{10}$ sampling head and pitot and between 18.8 and 26.5 inches for the $PM_{2.5}$ cyclone and pitot. A probe blockage factor is calculated because of the flow blockage caused by the relatively large cross-sectional area of the cyclone sampling head, as discussed in Section 8.3.2.2 and illustrated in Figures 8 and 9 of Section 17. You must determine the cross-sectional area of the cyclone head you use and determine its stack blockage factor. (Note: Commercially-available sampling heads (including the PM_{10} cyclone, $PM_{2.5}$ cyclone, pitot and filter holder) have a projected area of approximately 31.2 square inches when oriented into the gas stream.) As the probe is moved from the outermost to the innermost point, the amount of blockage that actually occurs ranges from approximately 13 square inches to the full 31.2 square inches plus the blockage caused by the probe extension. The average cross-sectional area blocked is 22 square inches.

* * * * *

8.7.5.5 * * *

(a) Container #1, Less than or equal to $PM_{2.5}$ micrometer filterable particulate. Use tweezers and/or clean disposable surgical gloves to remove the filter from the filter holder. Place the filter in the Petri dish that you labeled with the test identification and Container #1. Using a dry brush and/or a sharp-edged blade, carefully transfer any PM and/or filter fibers that adhere to the filter holder gasket or filter support screen to the Petri dish. Seal the container. This container holds particles less than or equal to 2.5 micrometers that are caught on the in-stack filter. (Note: If the test is conducted for PM_{10} only, then Container #1 would be for less than or equal to PM_{10} micrometer filterable particulate.)

* * * * *

10.1 Gas Flow Velocities. You must use an S-type pitot tube that meets the required EPA specifications (EPA Publication 600/4–77–0217b) during these velocity measurements. (Note: If, as specified in Section 8.7.2.3, testing is performed in stacks less than 26.5 inches in diameter, testers may use a standard pitot tube according to the requirements in Method 1 or 2 of appendix A–3 to part 60 of this chapter.) You must also complete the following:

* * * * *

11.2.1 Container #1, Less than or Equal to $PM_{2.5}$ Micrometer Filterable Particulate. Transfer the filter and any loose particulate from the sample container to a tared weighing dish or pan that is inert to solvent or mineral acids. Desiccate for 24 hours in a dessicator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. (See Section 3.0 for a definition of Constant weight.) If constant weight requirements cannot be met, the filter must be treated as described in Section 11.2.1 of Method 202 of appendix M to this part. Note: The nozzle and front half wash and filter collected at or below 30 °C (85 °F) may not be heated and must be maintained at or below 30 °C (85 °F).

* * * * *

12.5 * * *

For N_{re} Less than 3,162:

$$Q_{IV} = 0.0060639 \left[\frac{\mu}{C^{0.4242}}\right] \left[\frac{P_s M_w}{T_s}\right]^{-0.5759} \left[\frac{1}{D_{50}}\right]^{0.8481} \quad \text{(Eq. 8)}$$

For N_{re} greater than or equal to 3,162:

$$Q_{IV} = 0.07657 \left[\frac{\mu}{C^{0.6205}}\right] \left[\frac{P_s M_w}{T_s}\right]^{-0.3795} \left[\frac{1}{D_{50}}\right]^{1.241} \quad \text{(Eq. 9)}$$

* * * * *

Method 202—Dry Impinger Method for Determining Condensable Particulate Emissions From Stationary Sources

* * * * *

7.2.1 Acetone. Use acetone that is stored in a glass bottle. Do not use acetone from a metal container because it normally produces a high residual mass in the laboratory and field reagent blanks. You must use acetone that has a blank value less than 1.0 ppmw (0.1 mg/100 g) residue.

7.2.2 Hexane, American Chemical Society grade. You must use hexane that has a blank residual mass value less than 1.0 ppmw (0.1 mg/100 g) residue.

* * * * *

8.5.1 Impinger and CPM Filter Assembly.

8.5.1.1 Monitor the moisture condensation in the knockout and backup impingers. If the accumulated water from moisture condensation overwhelms the knockout impinger, i.e., the water level is more than approximately one-half the capacity of the knockout impinger, or if water accumulates in the backup impinger sufficient to cover the impinger insert tip, then you may interrupt the sampling run, recover and weigh the moisture accumulated in the knockout and backup impinger, reassemble and leak check the sampling train, and resume the sampling run. You must purge the water collected during the test interruption as soon as practical following the procedures in Section 8.5.3.

8.5.1.2 You must include the weight or volume of the moisture in your moisture calculation and you must combine the recovered water with the appropriate sample fraction for subsequent CPM analysis.

8.5.1.3 Use the field data sheet for the filterable particulate method to record the CPM filter temperature readings at the beginning of each sample time increment and when sampling is halted. Maintain the CPM filter greater than 20 °C (greater than 65 °F) but less than or equal to 30 °C (less than or equal to 85 °F) during sample collection. (Note: Maintain the temperature of the CPM filter assembly as close to 30 °C (85 °F) as feasible.)

* * * * *

8.5.3.1 If you choose to conduct a pressurized nitrogen purge at the completion of CPM sample collection, you may purge the entire CPM sample collection train from the condenser inlet to the CPM filter holder outlet or you may quantitatively transfer the water collected in the condenser and the water dropout impinger to the backup impinger and purge only the backup impinger and the CPM filter. You must measure the water in the knockout and backup impingers and record the volume or weight as part of the moisture collected during sampling as specified in Section 8.5.3.4.

8.5.3.1.1 If you choose to conduct a purge of the entire CPM sampling train, you must replace the short stem impinger insert in the knock out impinger with a standard modified Greenburg Smith impinger insert.

8.5.3.1.2 If you choose to combine the knockout and backup impinger catch prior to purge, you must purge the backup impinger and CPM filter holder.

8.5.3.1.3 If the tip of the impinger insert does not extend below the water level (including the water transferred from the first impinger if this option was chosen), you must add a measured amount of degassed, deionized ultra-filtered water that contains 1 ppmw (1 mg/L) residual mass or less until the impinger tip is at least 1 centimeter below the surface of the water. You must record the amount of water added to the water dropout impinger (Vp)(see Figure 4 of Section 18) to correct the moisture content of the effluent gas. (Note: Prior to use, water

must be degassed using a nitrogen purge bubbled through the water for at least 15 minutes to remove dissolved oxygen).

8.5.3.1.4 To perform the nitrogen purge using positive pressure nitrogen flow, you must start with no flow of gas through the clean purge line and fittings. Connect the filter outlet to the input of the impinger train and disconnect the vacuum line from the exit of the silica moisture collection impinger (see Figure 3 of Section 18). You may purge only the CPM train by disconnecting the moisture train components if you measure moisture in the field prior to the nitrogen purge. You must increase the nitrogen flow gradually to avoid over-pressurizing the impinger array. You must purge the CPM train at a minimum of 14 liters per minute for at least one hour. At the conclusion of the purge, turn off the nitrogen delivery system.

* * * * *

11.2.1 Container #3, CPM Filter Sample. If the sample was collected by Method 17 or Method 201A with a stack temperature below 30 °C (85 °F), transfer the filter and any loose PM from the sample container to a tared glass weighing dish. (See Section 3.0 for a definition of constant weight.) Desiccate the sample for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. [Note: In-stack filter samples collected at 30 °C (85 °F) may include both filterable insoluble particulate and condensable particulate. The nozzle and front half wash and filter collected at or below 30 °C (85 °F) may not be heated and must be maintained at or below 30 °C (85 °F).]

11.2.2 CPM Container #1, Aqueous Liquid Impinger Contents. Analyze the water soluble CPM in Container #1 as described in this section. Place the contents of Container #1 into a separatory funnel. Add approximately 30 ml of hexane to the funnel, mix well, and pour off the upper organic phase. Repeat this procedure twice with 30 ml of hexane each time combining the organic phase from each extraction. Each time, leave a small amount of the organic/hexane phase in the separatory funnel, ensuring that no water is collected in the organic phase. This extraction should yield about 90 ml of organic extract. Combine the organic extract from Container #1 with the organic train rinse in Container #2.

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18.0 * * *

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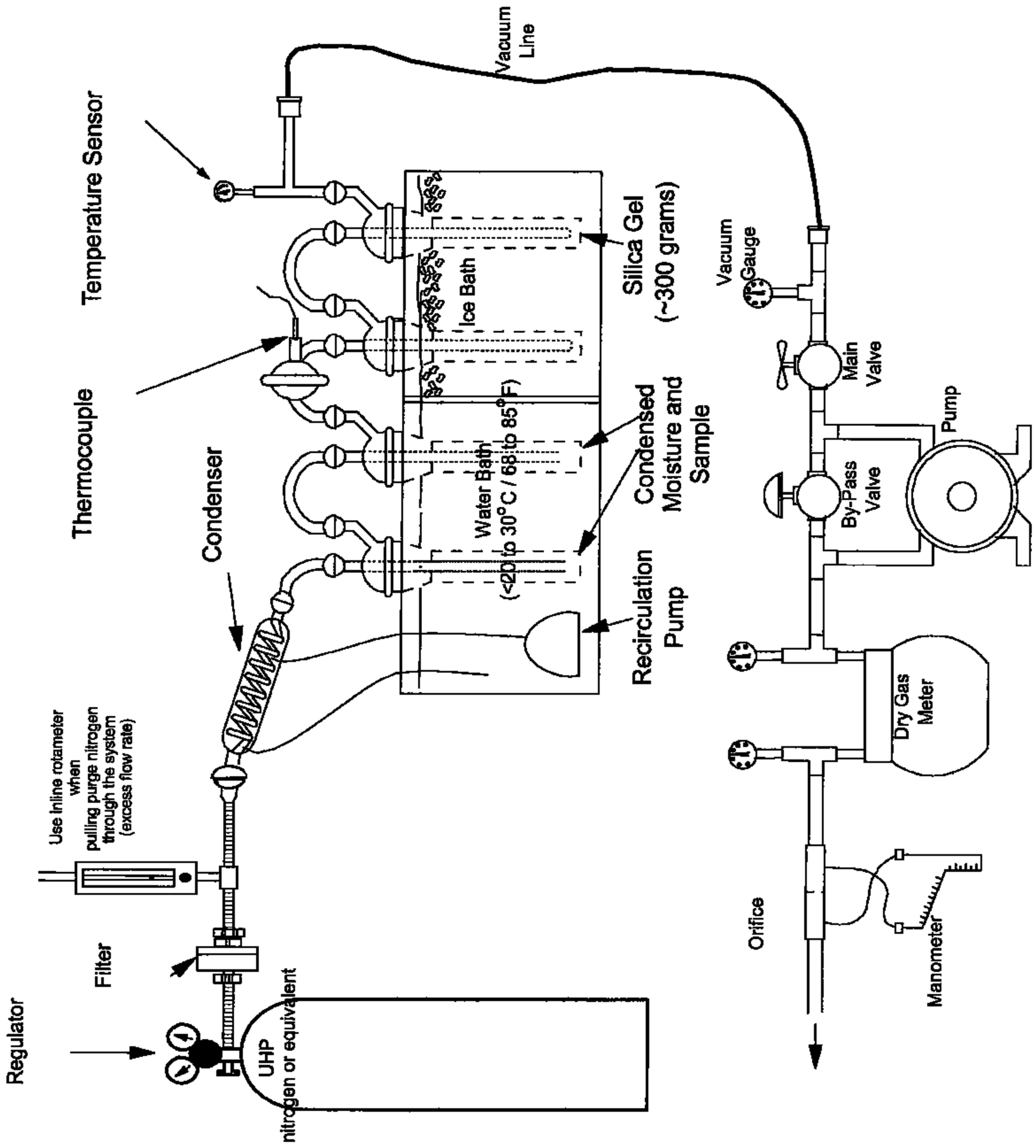

Figure 2. Nitrogen Purge Train Configuration (Vacuum Purge)

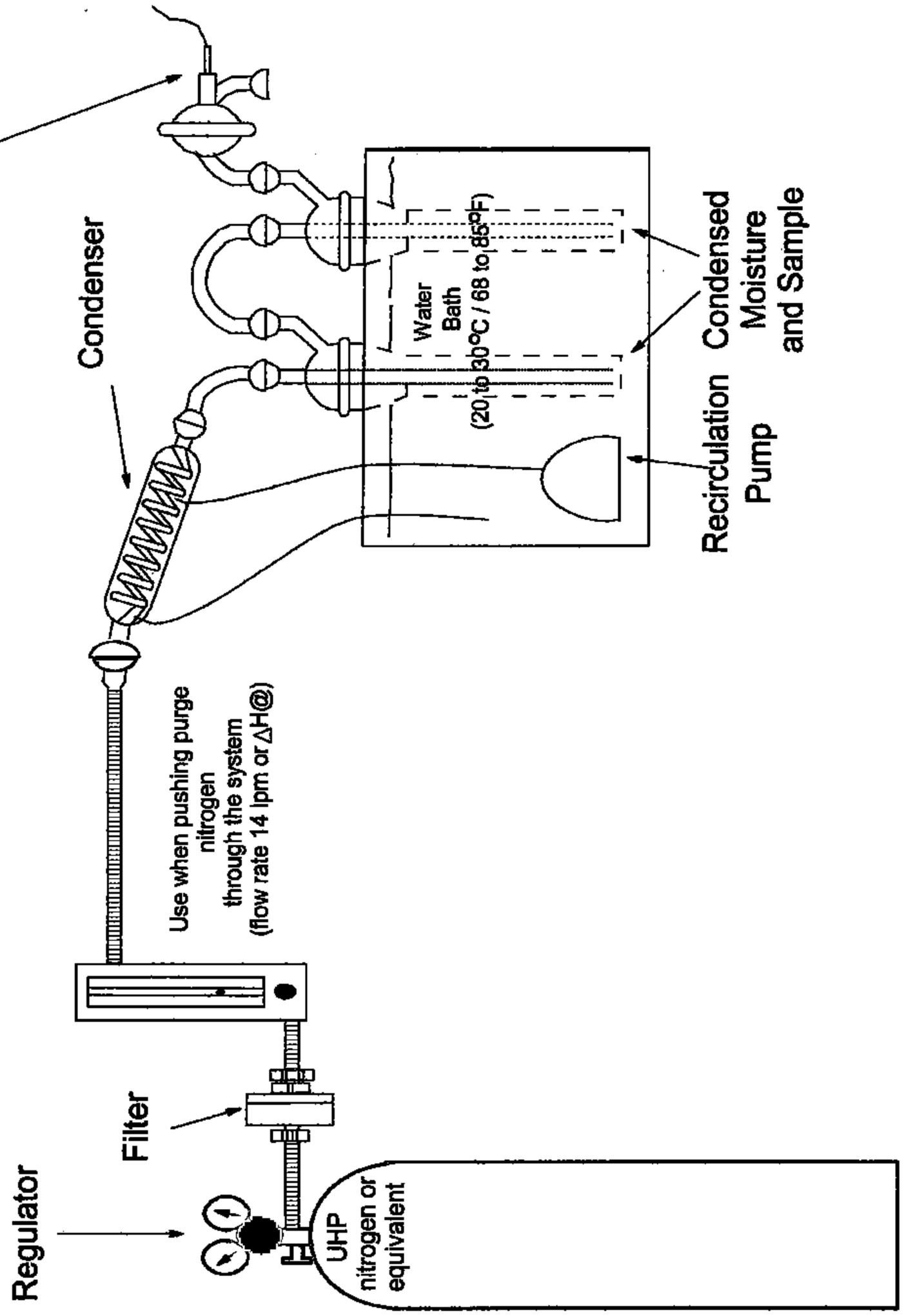

Figure 3. Nitrogen Purge Train Configuration (Pressure Purge)

Field Train Recovery Blank Condensable Particulate Calculations	
Plant	
Date	
Blank No.	
CPM Filter No.	
Water volume added to purge train (V_p)	ml
Field Reagent Blank Mass[a]	
Water (Section 11.2.7)	mg
Acetone (Section 11.2.6)	mg
Hexane (Section 11.2.8)	mg
Field Train Recovery Blank Mass	
Mass of Organic CPM (m_{ob}) (Section 11.2.3)	mg
Mass of Inorganic CPM (m_{ib}) (Equation 3)	mg
Mass of the Field Train Recovery Blank (not to exceed 2.0 mg) (Equation 2)	mg

[a]Field reagent blanks are optional and intended to provide the testing contractor with information they can use to implement corrective actions, if necessary, to reduce the residual mass contribution from reagents used in the field. Field reagent blanks are not used to correct the CPM measurement results.

Figure 4. Field Train Recovery Blank Condensable Particulate Calculations

Other Field Train Sample Condensable Particulate Data	
Plant	
Date	
Run No.	
CPM Filter No.	
Water volume added to purge train (max 50 ml) (V_p)	ml
Date	
Run No.	
CPM Filter No.	
Water volume added to purge train (max 50 ml) (V_p)	ml
Date	
Run No.	
CPM Filter No.	
Water volume added to purge train (max 50 ml) (V_p)	ml

Figure 5. Other Field Train Sample Condensable Particulate Data

Calculations for Recovery of Condensable PM (CPM)		
Plant		
Date		
Run No.		
Sample Preparation - CPM Containers No. 1 and 2 (Section 11.1)		
Was significant volume of water lost during transport? Yes or No		
If Yes, measure the volume received.		
Estimate the volume lost during transport.		ml
Was significant volume of organic rinse lost during transport? Yes or No		
If Yes, measure the volume received.		
Estimate the volume lost during transport.		ml
For Titration		
Normality of NH_4OH (N) (Section 10.2)		N
Volume of titrant (V_t) (Section 11.2.2.2)		ml
Mass of NH_4 added (m_c) (Equation 1)		mg
For CPM Blank Weights		
Inorganic Field Train Recovery Blank Mass (m_{ib}) (Section 9.9)		mg
Organic Field Train Recovery Blank Mass (m_{ob}) (Section 9.9)		mg
Mass of Field Train Recovery Blank (M_{fb}) (max. 2 mg) (Equation 2)		mg
For CPM Train Weights		
Mass of Organic CPM (m_o) (Section 11.2.3)		mg
Mass of Inorganic CPM (m_i) (Equation 3)		mg
Total CPM Mass (m_{cpm}) (Equation 4)		mg

Figure 6. CPM Work Table

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PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

Subpart A—[Amended]

■ 4. Amend § 60.8 by revising paragraph (g)(1) and adding new paragraphs (h) and (i) to read as follows:

§ 60.8 Performance tests.

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(g) * * *

(1) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A–3 of part 60, Methods 6C, 7E, 9, and 10 of appendix A–4 of part 60, Methods 18 and 19 of appendix A–6 of part 60, Methods 20, 22, and 25A of appendix A–7 of part 60, Methods 30A and 30B of appendix A–8 of part 60, and Methods 303, 318, 320, and 321 of appendix A of part 63 of this chapter. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, *www.epa.gov/ttn/emc,* to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to

include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request and the compliance authority may grant a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

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(h) Unless otherwise specified in the applicable subpart, each test location must be verified to be free of cyclonic flow and evaluated for the existence of emission gas stratification and the required number of sampling traverse points. If other procedures are not specified in the applicable subpart to the regulations, use the appropriate procedures in Method 1 to check for cyclonic flow and Method 7E to evaluate emission gas stratification and selection of sampling points.

(i) Whenever the use of multiple calibration gases is required by a test method, performance specification, or quality assurance procedure in a part 60 standard or appendix, Method 205 of 40 CFR part 51, appendix M of this chapter, "Verification of Gas Dilution Systems for Field Instrument Calibrations," may be used.

■ 5. Amend § 60.13 by revising paragraph (d)(1) to read as follows:

§ 60.13 Monitoring requirements.

* * * * *

(d)(1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once each operating day in accordance with a written procedure. The zero and span must, at a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part must check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is defined in the applicable version of PS–1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

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■ 6. Revise § 60.17 to read as follows:

§ 60.17 Incorporations by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the EPA must publish notice of change in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at the Air and Radiation Docket and Information Center, U.S. EPA, 401 M St. SW., Washington, DC, telephone number 202–566, and is available from the sources listed below. It is also available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030 or go to *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(b) American Gas Association, available through ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990), IBR approved for § 60.107a(d).

(2) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 2: Specification and Installation Requirements (2000), IBR approved for § 60.107a(d).

(3) American Gas Association Report No. 11: Measurement of Natural Gas by Coriolis Meter (2003), IBR approved for § 60.107a(d).

(4) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Revised February 2006), IBR approved for § 60.107a(d).

(c) American Hospital Association (AHA) Service, Inc., Post Office Box 92683, Chicago, Illinois 60675–2683. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center (Docket A–91–61, Item IV–J–124), Room M–1500, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

(1) An Ounce of Prevention: Waste Reduction Strategies for Health Care Facilities. American Society for Health Care Environmental Services of the American Hospital Association. Chicago, Illinois. 1993. AHA Catalog No. 057007. ISBN 0–87258–673–5. IBR approved for §§ 60.35e and 60.55c.

(2) [Reserved]

(d) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005.

(1) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February 1980, IBR approved for §§ 60.111(i), 60.111a(f), and 60.116b(e).

(2) API Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005, IBR approved for § 60.107a(d).

(e) American Public Health Association, 1015 18th Street NW., Washington, DC 20036.

(1) "Standard Methods for the Examination of Water and Wastewater," 16th edition, 1985. Method 303F: "Determination of Mercury by the Cold Vapor Technique." Incorporated by reference for appendix A–8 to part 60, Method 29, §§ 9.2.3, 10.3, and 11.1.3.

(2) 2540 G. Total, Fixed, and Volatile Solids in Solid and Semisolid Samples, in Standard Methods for the Examination of Water and Wastewater, 20th Edition, 1998, IBR approved for § 60.154(b).

(f) American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990, Telephone (800) 843–2763, *http://www.asme.org.*

(1) ASME Interim Supplement 19.5 on Instruments and Apparatus: Application, Part II of Fluid Meters, 6th Edition (1971), IBR approved for §§ 60.58a(h), 60.58b(i), 60.1320(a), and 60.1810(a).

(2) ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, IBR approved for § 60.107a(d).

(3) ASME/ANSI MFC–4M–1986 (Reaffirmed 2008), Measurement of Gas Flow by Turbine Meters, IBR approved for § 60.107a(d).

(4) ASME/ANSI MFC–5M–1985 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for § 60.107a(d).

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

(6) ASME/ANSI MFC–7M–1987 (Reaffirmed 2006), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for § 60.107a(d).

(7) ASME/ANSI MFC–9M–1988 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for § 60.107a(d).

(8) ASME MFC–11M–2006, Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for § 60.107a(d).

(9) ASME MFC–14M–2003, Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for § 60.107a(d).

(10) ASME MFC–16–2007, Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters, IBR approved for § 60.107a(d).

(11) ASME MFC–18M–2001, Measurement of Fluid Flow Using Variable Area Meters, IBR approved for § 60.107a(d).

(12) ASME MFC–22–2007, Measurement of Liquid by Turbine Flowmeters, IBR approved for § 60.107a(d).

(13) ASME PTC 4.1–1964 (Reaffirmed 1991), Power Test Codes: Test Code for Steam Generating Units (with 1968 and 1969 Addenda), IBR approved for §§ 60.46b, 60.58a(h), 60.58b(i), 60.1320(a), and 60.1810(a).

(14) ASME/ANSI 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 to subpart EEEE, tables 2 and 4 to subpart FFFF, table 2 to subpart JJJJ, §§ 60.4415(a), 60.2145(s) and (t), 60.2710(s), (t), and (w), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§ 60.5406(c) and 60.5413(b).

(15) ASME QRO–1–1994, Standard for the Qualification and Certification of Resource Recovery Facility Operators, IBR approved for §§ 60.54b(a) and (b), 60.56a, 60.1185(a) and (c), and 60.1675(a) and (c).

(g) American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; also available through ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106.

(1) ASTM A99–76, Standard Specification for Ferromanganese, IBR approved for § 60.261.

(2) ASTM A99–82 (Reapproved 1987), Standard Specification for Ferromanganese, IBR approved for § 60.261.

(3) ASTM A100–69, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(4) ASTM A100–74, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(5) ASTM A100–93, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(6) ASTM A101–73, Standard Specification for Ferrochromium, IBR approved for § 60.261.

(7) ASTM A101–93, Standard Specification for Ferrochromium, IBR approved for § 60.261.

(8) ASTM A482–76, Standard Specification for Ferrochromesilicon, IBR approved for § 60.261.

(9) ASTM A482–93, Standard Specification for Ferrochromesilicon, IBR approved for § 60.261.

(10) ASTM A483–64, Standard Specification for Silicomanganese, IBR approved for § 60.261.

(11) ASTM A483–74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for § 60.261.

(12) ASTM A495–76, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for § 60.261.

(13) ASTM A495–94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for § 60.261.

(14) ASTM D86–78, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h).

(15) ASTM D86–82, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h).

(16) ASTM D86–90, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h).

(17) ASTM D86–93, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h).

(18) ASTM D86–95, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h).

(19) ASTM D86–96, 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).

(20) ASTM D129–64, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j) and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(21) ASTM D129–78, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j) and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(22) ASTM D129–95, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j) and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(23) ASTM D129–00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for § 60.335(b).

(24) ASTM D129–00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for § 60.4415(a).

(25) ASTM D240–76, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§ 60.46(c), 60.296(b), and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(26) ASTM D240–92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§ 60.46(c), 60.296(b), and appendix A–7: Method 19, Section 12.5.2.2.3.

(27) ASTM D240–02 (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon

Fuels by Bomb Calorimeter, (Approved May 1, 2007), IBR approved for § 60.107a(d).

(28) ASTM D270–65, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.2.1.

(29) ASTM D270–75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.2.1.

(30) ASTM D323–82, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§ 60.111(l), 60.111a(g), 60.111b, and 60.116b(f).

(31) ASTM D323–94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§ 60.111(l), 60.111a(g), 60.111b, and 60.116b(f).

(32) ASTM D388–77, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(33) ASTM D388–90, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(34) ASTM D388–91, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(35) ASTM D388–95, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(36) ASTM D388–98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(37) ASTM D388–99 (Reapproved 2004)ε,[1] Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(38) ASTM D396–78, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(39) ASTM D396–89, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(40) ASTM D396–90, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(41) ASTM D396–92, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(42) ASTM D396–98, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(43) ASTM D975–78, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).

(44) ASTM D975–96, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).

(45) ASTM D975–98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).

(46) ASTM D975–08a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.41b and 60.41c.

(47) ASTM D1072–80, Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b).

(48) ASTM D1072–90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b).

(49) ASTM D1072–90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.4415(a).

(50) ASTM D1137–53, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for § 60.45(f).

(51) ASTM D1137–75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for § 60.45(f).

(52) ASTM D1193–77, Standard Specification for Reagent Water, IBR approved for appendix A–3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A–4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A–5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A–8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(53) ASTM D1193–91, Standard Specification for Reagent Water, IBR approved for appendix A–3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A–4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A–5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A–8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(54) ASTM D1266–87, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).

(55) ASTM D1266–91, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).

(56) ASTM D1266–98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).

(57) ASTM D1266–98 (Reapproved 2003)ε,[1] Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for § 60.4415(a).

(58) ASTM D1475–60 (Reapproved 1980), Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for § 60.435(d), appendix A–8 to part 60: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.

(59) ASTM D1475–90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for § 60.435(d), appendix A–8 to part 60: Method 24, Section 6.1; and Method 24A, §§ 6.5 and 7.1.

(60) ASTM D1552–83, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j), 60.335(b), and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(61) ASTM D1552–95, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j), 60.335(b), and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(62) ASTM D1552–01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j), 60.335(b), and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(63) ASTM D1552–03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for § 60.4415(a).

(64) ASTM D1826–77, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), 60.296(b), and appendix A–7 to part 60: Method 19, Section 12.3.2.4.

(65) ASTM D1826–94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), 60.296(b), and appendix A–7 to part 60: Method 19, Section 12.3.2.4.

(66) ASTM D1826–94 (Reapproved 2003), Standard Test Method for

Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, (Approved May 10, 2003), IBR approved for § 60.107a(d).

(67) ASTM D1835–87, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(68) ASTM D1835–91, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(69) ASTM D1835–97, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(70) ASTM D1835–03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(71) ASTM D1945–64, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(72) ASTM D1945–76, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(73) ASTM D1945–91, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(74) ASTM D1945–96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(75) ASTM D1945–03 (Reapproved 2010), Standard Method for Analysis of Natural Gas by Gas Chromatography, (Approved January 1, 2010), IBR approved for §§ 60.107a(d) and 60.5413(d).

(76) ASTM D1946–77, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.18(f), 60.45(f), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(77) ASTM D1946–90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.18(f), 60.45(f), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(78) ASTM D1946–90 (Reapproved 2006), Standard Method for Analysis of Reformed Gas by Gas Chromatography, (Approved June 1, 2006), IBR approved for § 60.107a(d).

(79) ASTM D2013–72, Standard Method of Preparing Coal Samples for Analysis, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(80) ASTM D2013–86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(81) ASTM D2015–77 (Reapproved 1978), Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), and appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(82) ASTM D2015–96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), and appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(83) ASTM D2016–74, Standard Test Methods for Moisture Content of Wood, IBR approved for appendix A–8 to part 60: Method 28, Section 16.1.1.

(84) ASTM D2016–83, Standard Test Methods for Moisture Content of Wood, IBR approved for appendix A–8 to part 60: Method 28, Section 16.1.1.

(85) ASTM D2234–76, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.1.

(86) ASTM D2234–96, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.1.

(87) ASTM D2234–97b, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.1.

(88) ASTM D2234–98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.1.

(89) ASTM D2369–81, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A–8 to part 60: Method 24, Section 6.2.

(90) ASTM D2369–87, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A–8 to part 60: Method 24, Section 6.2.

(91) ASTM D2369–90, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A–8 to part 60: Method 24, Section 6.2.

(92) ASTM D2369–92, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A–8 to part 60: Method 24, Section 6.2.

(93) ASTM D2369–93, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A–8 to part 60: Method 24, Section 6.2.

(94) ASTM D2369–95, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A–8 to part 60: Method 24, Section 6.2.

(95) ASTM D2382–76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§ 60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(96) ASTM D2382–88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§ 60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(97) ASTM D2504–67, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).

(98) ASTM D2504–77, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).

(99) ASTM D2504–88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).

(100) ASTM D2584–68(Reapproved 1985), Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c).

(101) ASTM D2584–94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c).

(102) ASTM D2597–94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for § 60.335(b).

(103) ASTM D2622–87, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§ 60.106(j) and 60.335(b).

(104) ASTM D2622–94, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§ 60.106(j) and 60.335(b).

(105) ASTM D2622–98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§ 60.106(j) and 60.335(b).

(106) ASTM D2622–05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a).

(107) ASTM D2879–83Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§ 60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).

(108) ASTM D2879–96, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition

Temperature of Liquids by Isoteniscope, IBR approved for §§ 60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).

(109) ASTM D2879–97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§ 60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).

(110) ASTM D2880–78, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§ 60.111(b), 60.111a(b), and 60.335(d).

(111) ASTM D2880–96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§ 60.111(b), 60.111a(b), and 60.335(d).

(112) ASTM D2908–74, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for § 60.564(j).

(113) ASTM D2908–91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for § 60.564(j).

(114) ASTM D2986–71, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for appendix A–3 to part 60: Method 5, Section 7.1.1; appendix A–5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(115) ASTM D2986–78, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for appendix A–3 to part 60: Method 5, Section 7.1.1; appendix A–5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(116) ASTM D2986–95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for appendix A–3 to part 60: Method 5, Section 7.1.1; appendix A–5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(117) ASTM D3173–73, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(118) ASTM D3173–87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(119) ASTM D3176–74, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for § 60.45(f)(5)(i) and appendix A–7 to part 60: Method 19, Section 12.3.2.3.

(120) ASTM D3176–89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for § 60.45(f)(5)(i) and appendix A–7 to part 60: Method 19, Section 12.3.2.3.

(121) ASTM D3177–75, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(122) ASTM D3177–89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(123) ASTM D3178–73 (Reapproved 1979), Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for § 60.45(f).

(124) ASTM D3178–89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for § 60.45(f).

(125) ASTM D3246–81, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).

(126) ASTM D3246–92, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).

(127) ASTM D3246–96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).

(128) ASTM D3246–05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.4415(a)(1).

(129) ASTM D3270–73T, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A–5 to part 60: Method 13A, Section 16.1.

(130) ASTM D3270–80, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A–5 to part 60: Method 13A, Section 16.1.

(131) ASTM D3270–91, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A–5 to part 60: Method 13A, Section 16.1.

(132) ASTM D3270–95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A–5 to part 60: Method 13A, Section 16.1.

(133) ASTM D3286–85, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(134) ASTM D3286–96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(135) ASTM D3370–76, Standard Practices for Sampling Water, IBR approved for § 60.564(j).

(136) ASTM D3370–95a, Standard Practices for Sampling Water, IBR approved for § 60.564(j).

(137) ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, (Approved May 10, 2003), IBR approved for §§ 60.107a(d) and 60.5413(d).

(138) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§ 60.41b and 60.41c.

(139) ASTM D3792–79, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A–7 to part 60: Method 24, Section 6.3.

(140) ASTM D3792–91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A–7 to part 60: Method 24, Section 6.3.

(141) ASTM D4017–81, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A–7 to part 60: Method 24, Section 6.4.

(142) ASTM D4017–90, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A–7 to part 60: Method 24, Section 6.4.

(143) ASTM D4017–96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A–7 to part 60: Method 24, Section 6.4.

(144) ASTM D4057–81, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(145) ASTM D4057–95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(146) ASTM D4057–95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a).

(147) ASTM D4084–82, Standard Test Method for Analysis of Hydrogen

Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.334(h).

(148) ASTM D4084–94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.334(h).

(149) ASTM D4084–05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§ 60.4360 and 60.4415(a).

(150) ASTM D4177–95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.2.1.

(151) ASTM D4177–95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a).

(152) ASTM D4239–85, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(153) ASTM D4239–94, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(154) ASTM D4239–97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(155) ASTM D4294–02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.335(b).

(156) ASTM D4294–03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a).

(157) ASTM D4442–84, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for appendix A–8 to part 60: Method 28, Section 16.1.1.

(158) ASTM D4442–92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for appendix A–8 to part 60: Method 28, Section 16.1.1.

(159) ASTM D4444–92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for appendix A–8 to part 60: Method 28, Section 16.1.1.

(160) ASTM D4457–85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1,1,1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for appendix A–7 to part 60: Method 24, Section 6.5.

(161) ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§ 60.335(b) and 60.4415(a).

(162) ASTM D4468–85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, (Approved June 1, 2006), IBR approved for § 60.107a(e).

(163) ASTM D4629–02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for §§ 60.49b(e) and 60.335(b).

(164) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§ 60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(d), 60.664(e), and 60.704(d).

(165) ASTM D4809–06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), (Approved December 1, 2006), IBR approved for § 60.107a(d).

(166) ASTM D4810–88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§ 60.4360 and 60.4415(a).

(167) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, (Approved June 1, 2006), IBR approved for §§ 60.107a(d) and 60.5413(d).

(168) ASTM D5287–97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for § 60.4415(a).

(169) ASTM D5403–93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for appendix A–7 to part 60: Method 24, Section 6.6.

(170) ASTM D5453–00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.335(b).

(171) ASTM D5453–05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.4415(a).

(172) ASTM D5504–01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§ 60.334(h) and 60.4360.

(173) ASTM D5504–08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, (Approved June 15, 2008), IBR approved for §§ 60.107a(e) and 60.5413(d).

(174) ASTM D5762–02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for § 60.335(b).

(175) ASTM D5865–98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for §§ 60.45(f) and 60.46(c), and appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(176) ASTM D5865–10, Standard Test Method for Gross Calorific Value of Coal and Coke, (Approved January 1, 2010), IBR approved for §§ 60.45(f), 60.46(c), and appendix A–7 to part 60: Method 19, section 12.5.2.1.3.

(177) ASTM D6216–98, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, IBR approved for appendix B to part 60: Performance Specification 1.

(178) ASTM D6228–98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for § 60.334(h).

(179) ASTM D6228–98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§ 60.4360 and 60.4415.

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

(181) ASTM D6366–99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for § 60.335(b)(9).

(182) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, (Approved October 1, 2004), IBR approved for § 60.107a(d) and table 2 to subpart JJJJ.

(183) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 60.335(a).

(184) 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 to subpart JJJJ, and §§ 60.5413(b) and (d).

(185) ASTM D6667–01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.335(b).

(186) ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.4415(a).

(187) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b and 60.41c.

(188) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for § 60.56c(b) and appendix B to part 60: Performance Specification 12A, Section 8.6.2.

(189) 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 §§ 60.2165(j) and 60.2730(j), tables 1, 5, 6 and 8 to subpart CCCC, and tables 2, 6, 7, and 9 to subpart DDDD, §§ 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, and tables 2 and 3 to subpart MMMM.

(190) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b and 60.41c.

(191) ASTM E168–67, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(192) ASTM E168–77, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(193) ASTM E168–92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), 60.632(f), and 60.5400.

(194) ASTM E169–63, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f) .

(195) ASTM E169–77, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), and 60.593a(b), 60.632(f).

(196) ASTM E169–93, General Techniques of Ultraviolet 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).

(197) ASTM E260–73, General Gas Chromatography Procedures, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(198) ASTM E260–91, General Gas Chromatography Procedures, (IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(199) ASTM E260–96, General Gas Chromatography Procedures, (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).

(200) ASTM E1584–11, Standard Test Method for Assay of Nitric Acid, (Approved August 1, 2011), IBR approved for § 60.73a(c).

(201) ASTM UOP539–97, Refinery Gas Analysis by Gas Chromatography, (Copyright 1997), IBR approved for § 60.107a(d).

(h) Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209.

(1) AOAC Method 9, Official Methods of Analysis of the Association of Official Analytical Chemists (AOAC), 11th edition, 1970, pp. 11–12, IBR approved for §§ 60.204(b), 60.214(b), 60.224(b), and 60.234(b).

(2) [Reserved]

(i) U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW., Washington, DC 20460, (202) 272–0167, *http://www.epa.gov.*

(1) EPA–454/R–98–015, Office of Air Quality Planning and Standards (OAQPS) Fabric Filter Bag Leak Detection Guidance, September 1997, IBR approved for §§ 60.2145(r), 60.2710(r), 60.4905(b), and 60.5225(b).

(2) [Reserved]

(j) The Gas Processors Association, 6526 East 60th Street, Tulsa, OK 74145; also available through Information Handling Services, 15 Inverness Way East, PO Box 1154, Englewood, CO 80150–1154. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460.

(1) Gas Processors Association Standard 2172–09, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (2009), IBR approved for § 60.107a(d).

(2) Gas Processors Association Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (2000), IBR approved for § 60.107a(d).

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

(k) International Organization for Standardization (ISO) available through IHS Inc., 15 Inverness Way East, Englewood, CO 80112.

(1) ISO 8178–4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—part 4: Test Cycles for Different Engine Applications, IBR approved for § 60.4241(b).

(2) [Reserved]

(l) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm.*

(1) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987–10–01)—First Edition, IBR approved for § 60.107a(d).

(2) [Reserved]

(m) This material is available for purchase from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center (Docket A–91–61, Item IV–J–125), Room M–1500, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

(1) OMB Bulletin No. 93–17: Revised Statistical Definitions for Metropolitan Areas. Office of Management and

Budget, June 30, 1993. NTIS No. PB 93–192–664. IBR approved for § 60.31e.

(2) [Reserved]

(n) North American Electric Reliability Corporation, 1325 G Street NW., Suite 600, Washington, DC 20005–3801, *http://www.nerc.com.*

(1) North American Electric Reliability Corporation Reliability Standard EOP–002–3, Capacity and Energy Emergencies, updated November 19, 2012, IBR approved for §§ 60.4211(f) and 60.4243(d). Also available online: *http://www.nerc.com/files/EOP-002-3_1.pdf.*

(2) [Reserved]

(o) Technical Association of the Pulp and Paper Industry (TAPPI), Dunwoody Park, Atlanta, GA 30341.

(1) TAPPI Method T624 os–68, IBR approved for § 60.285(d).

(2) [Reserved]

(p) Underwriter's Laboratories, Inc. (UL), 333 Pfingsten Road, Northbrook, IL 60062.

(1) UL 103, Sixth Edition revised as of September 3, 1986, Standard for Chimneys, Factory-built, Residential Type and Building Heating Appliance, IBR approved for Appendix A–8 to part 60.

(2) [Reserved]

(q) Water Pollution Control Federation (WPCF), 2626 Pennsylvania Avenue NW., Washington, DC 20037.

(1) Method 209A, Total Residue Dried at 103–105 °C, in Standard Methods for the Examination of Water and Wastewater, 15th Edition, 1980, IBR approved for § 60.683(b).

(2) [Reserved]

(r) West Coast Lumber Inspection Bureau, 6980 SW. Barnes Road, Portland, OR 97223.

(1) West Coast Lumber Standard Grading Rules No. 16, pages 5–21, 90 and 91, September 3, 1970, revised 1984, IBR approved for Appendix A–8 to part 60.

(2) [Reserved]

Subpart Db—[Amended]

■ 7. Amend § 60.46b by revising paragraphs (f)(1)(ii) and (h)(1) and (h)(2) to read as follows:

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

* * * * *

(f) * * *

(1) * * *

(ii) Method 7E of appendix A of this part or Method 320 of appendix A of part 63 shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

* * * * *

(h) * * *

(1) Conduct an initial performance test as required under § 60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under § 60.44b using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63 of this chapter, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_X emission standards under § 60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63, or other approved reference methods.

* * * * *

■ 8. Amend § 60.47b by revising paragraph (b)(2) to read as follows:

§ 60.47b Emission monitoring for sulfur dioxide.

* * * * *

(b) * * *

(2) Measuring SO_2 according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2 control system. An initial stratification test is required to verify the adequacy of the sampling location for Method 6B of appendix A of this part. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in Section 3.2 and the applicable procedures in Section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C or Method 320 of appendix A of part 63 of this chapter and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part, 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

* * * * *

Subpart Ec—[Amended]

■ 9. Amend § 60.51c by revising the definition of "Medical/infectious waste" to read as follows:

§ 60.51c Definitions.

* * * * *

Medical/infectious waste means any waste generated in the diagnosis, treatment, or immunization of human beings or animals, in research pertaining thereto, or in the production or testing of biologicals that are listed in paragraphs (1) through (7) of this definition. The definition of medical/infectious waste does not include hazardous waste identified or listed under the regulations in part 261 of this chapter; household waste, as defined in § 261.4(b)(1) of this chapter; ash from incineration of medical/infectious waste, once the incineration process has been completed; human corpses, remains, and anatomical parts that are intended for interment or cremation; and domestic sewage materials identified in § 261.4(a)(1) of this chapter.

(1) Cultures and stocks of infectious agents and associated biologicals, including: Cultures from medical and pathological laboratories; cultures and stocks of infectious agents from research and industrial laboratories; wastes from the production of biologicals; discarded live and attenuated vaccines; and culture dishes and devices used to transfer, inoculate, and mix cultures.

(2) Human pathological waste, including tissues, organs, and body parts and body fluids that are removed during surgery or autopsy, or other medical procedures, and specimens of body fluids and their containers.

(3) Human blood and blood products including:

(i) Liquid waste human blood;

(ii) Products of blood;

(iii) Items saturated and/or dripping with human blood; or

(iv) Items that were saturated and/or dripping with human blood that are now caked with dried human blood; including serum, plasma, and other blood components, and their containers, which were used or intended for use in either patient care, testing and laboratory analysis or the development of pharmaceuticals. Intravenous bags are also included in this category.

(4) Sharps that have been used in animal or human patient care or treatment or in medical, research, or industrial laboratories, including hypodermic needles, syringes (with or without the attached needle), pasteur pipettes, scalpel blades, blood vials, needles with attached tubing, and

culture dishes (regardless of presence of infectious agents). Also included are other types of broken or unbroken glassware that were in contact with infectious agents, such as used slides and cover slips.

(5) Animal waste including contaminated animal carcasses, body parts, and bedding of animals that were known to have been exposed to infectious agents during research (including research in veterinary hospitals), production of biologicals or testing of pharmaceuticals.

(6) Isolation wastes including biological waste and discarded materials contaminated with blood, excretions, exudates, or secretions from humans who are isolated to protect others from certain highly communicable diseases, or isolated animals known to be infected with highly communicable diseases.

(7) Unused sharps including the following unused, discarded sharps: hypodermic needles, suture needles, syringes, and scalpel blades.

* * * * *

Subpart H—[Amended]

■ 10. Amend § 60.84 by revising the equation in paragraph (d) to read as follows:

§ 60.84 Emission monitoring.

* * * * *

(d) * * *

$E_s = (C_s S)/[0.265 - (0.0126\ \%O_2) - (A\ \%CO_2)]$

* * * * *

Subpart O—[Amended]

■ 11. Amend § 60.154 by revising the introductory text to paragraph (b)(5) to read as follows:

§ 60.154 Test methods and procedures.

* * * * *

(b) * * *

(5) Samples of the sludge charged to the incinerator shall be collected in nonporous jars at the beginning of each run and at approximately 1-hour intervals thereafter until the test ends; and "2540 G. Total, Fixed, and Volatile Solids in Solid and Semisolid Samples, in Standard Methods for the Examination of Water and Wastewater, 20th Edition, 1998" (incorporated by reference—see § 60.17) shall be used to determine dry sludge content of each sample (total solids residue), except that:

* * * * *

Subpart BB—[Amended]

■ 12. Amend § 60.284 by revising the equation in paragraph (c)(3) to read as follows:

§ 60.284 Monitoring of emissions and operations.

* * * * *

(c) * * *

(3) * * *

$C_{corr} = C_{meas} \times (21 - X)/(21 - Y)$

* * *

* * * * *

Subpart GG—[Amended]

■ 13. Amend § 60.335 by revising the terms P_r and P_o for the equation in paragraph (b)(1) to read as follows:

§ 60.335 Test methods and procedures.

* * * * *

(b) * * *

(1) * * *

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure. Alternatively, you may use 760 mm Hg (29.92 in Hg),

P_o = observed combustor inlet absolute pressure at test, mm Hg. Alternatively, you may use the barometric pressure for the date of the test,

* * * * *

Subpart KK—[Amended]

■ 14. Amend § 60.374 by revising paragraphs (b)(1), (b)(2), and (c)(2) to read as follows:

§ 60.374 Test methods and procedures.

* * * * *

(b) * * *

(1) Method 12 or Method 29 shall be used to determine the lead concentration (C_{Pb}) and, if applicable, the volumetric flow rate (Q_{sda}) of the effluent gas. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf).

(2) When different operations in a three-process operation facility are ducted to separate control devices, the lead emission concentration (C) from the facility shall be determined as follows:

$$C = \left[\sum_{a=1}^{n}(C_a Q_{sda})\right] / \sum_{a=1}^{n} Q_{sda}$$

Where:

C = concentration of lead emissions for the entire facility, mg/dscm (gr/dscf).

C_a = concentration of lead emissions from facility "a", mg/dscm (gr/dscf).

Q_{sda} = volumetric flow rate of effluent gas from facility "a", dscm/hr (dscf/hr).

N = total number of control devices to which separate operations in the facility are ducted.

* * * * *

(c) * * *

(2) Method 12 or Method 29 shall be used to determine the lead concentration (C_{Pb}) and the volumetric flow rate (Q_{sd}) of the effluent gas. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf).

* * * * *

Subpart LL—[Amended]

■ 15. Amend § 60.382 by revising paragraph (a)(1) to read as follows:

§ 60.382 Standard for particulate matter.

(a) * * *

(1) Contain particulate matter in excess of 0.05 grams per dry standard cubic meter (0.05 g/dscm).

* * * * *

■ 16. Amend § 60.386 by revising paragraph (b)(2) to read as follows:

§ 60.386 Test methods and procedures.

* * * * *

(b) * * *

(2) Method 9 and the procedures in § 60.11 shall be used to determine opacity from stack emissions and process fugitive emissions. The observer shall read opacity only when emissions are clearly identified as emanating solely from the affected facility being observed. A single visible emission observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval. This option is subject to the following limitations:

(i) No more than three emission points are read concurrently;

(ii) All three emission points must be within a 70° viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points; and

(iii) If an opacity reading for any one of the three emission points is within 5 percent opacity of the application standard, then the observer must stop taking readings for the other two points and continue reading just that single point.

* * * * *

Subpart UU—[Amended]

■ 17. Amend § 60.472 by revising paragraph (a)(1)(ii) to read as follows:

§ 60.472 Standards for particulate matter.

(a) * * *

(1) * * *

(ii) 0.4 kg/Mg (0.8 lb/ton) of saturated felt or smooth-surfaced roll roofing produced;

* * * * *

Subpart NNN—[Amended]

■ 18. Amend § 60.660 by revising paragraph (c)(4) to read as follows:

§ 60.660 Applicability and designation of affected facility.

* * * * *

(c) * * *

(4) Each affected facility that has a total resource effectiveness (TRE) index value greater than 8.0 is exempt from all provisions of this subpart except for §§ 60.662; 60.664 (e), (f), and (g); and 60.665 (h) and (l).

* * * * *

■ 19. Amend § 60.665 by revising paragraphs (h)(2) and (h)(3) to read as follows:

§ 60.665 Reporting and recordkeeping requirements.

* * * * *

(h) * * *

(2) Any recalculation of the TRE index value performed pursuant to § 60.664(g); and

(3) The results of any performance test performed pursuant to the methods and procedures required by § 60.664(e).

* * * * *

Subpart IIII—[Amended]

■ 20. Revise Table 7 to Subpart IIII of part 60 to read as follows:

As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:

TABLE 7 TO SUBPART IIII OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS FOR STATIONARY CI ICE WITH A DISPLACEMENT OF ≥30 LITERS PER CYLINDER

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more;	i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A–1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A–4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A–2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A–3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A–4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17)	(d) NO_X 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.

TABLE 7 TO SUBPART IIII OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS FOR STATIONARY CI ICE WITH A DISPLACEMENT OF ≥30 LITERS PER CYLINDER—Continued

Each	Complying with the requirement to	You must	Using	According to the following requirements
	b Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A–1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A–4.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A–2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A–3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, Appendix A–4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_X 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.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A–1	(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;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A–2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A–3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.

TABLE 7 TO SUBPART IIII OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS FOR STATIONARY CI ICE WITH A DISPLACEMENT OF ≥30 LITERS PER CYLINDER—Continued

Each	Complying with the requirement to	You must	Using	According to the following requirements
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A–3	(d) PM 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.
	d. Limit the concentration of PM in the stationary CI 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–1	(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 of 40 CFR part 60, appendix A–2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A–3	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A–3.	(d) PM 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.

Subpart JJJJ—[Amended]

■ 21. Revise Table 2 to Subpart JJJJ of part 60 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/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A–1, if measuring flow rate.	(a) Alternatively, for NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		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–2 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 2C of 40 CFR part 60, appendix A–1 or Method 19 of 40 CFR part 60, appendix A–7.	
		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–3, Method 320 of 40 CFR part 63, appendix A, or ASTM Method D 6348–03[e].	(c) Measurements to determine moisture must be made at the same time as the measurement for NO_X concentration.
		v. Measure NO_X at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(5) Method 7E of 40 CFR part 60, appendix A–4, ASTM Method D6522–00 (Reapproved 2005)[a e], Method 320 of 40 CFR part 63, appendix A, or ASTM Method D 6348–03[e].	(d) Results of this test consist of the average of the three 1-hour or longer runs.

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
	b limit the concentration of CO in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A–1, if measuring flow rate.	(a) Alternatively, for CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		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–2 or ASTM Method D6522–00 (Reapproved 2005) [a c].	(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 2C of 40 CFR part 60, appendix A–1 or Method 19 of 40 CFR part 60, appendix A–7.	
		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–3, Method 320 of 40 CFR part 63, appendix A, or ASTM Method 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; if using a control device, the sampling site must be located at the outlet of the control device.	(5) Method 10 of 40 CFR part 60, appendix A4, ASTM Method D6522–00 (Reapproved 2005) [a e], Method 320 of 40 CFR part 63, appendix A, or ASTM Method D 6348–03 [e].	(d) Results of this test consist of the average of the three 1-hour or longer runs.

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
	c. limit the concentration of VOC in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A–1, if measuring flow rate.	(a) Alternatively, for VOC, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		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–2 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 2C of 40 CFR part 60, appendix A–1 or Method 19 of 40 CFR part 60, appendix A–7.	
		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–3, Method 320 of 40 CFR part 63, appendix A, or ASTM Method D 6348–03 [e].	(c) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.
		v. Measure VOC at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(5) Methods 25A and 18 of 40 CFR part 60, appendices A–6 and A–7, 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–6 [c d], Method 320 of 40 CFR part 63, appendix A, or ASTM Method D 6348–03 [e].	(d) Results of this test consist of the average of the three 1-hour or longer runs.

[a] Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

[b] You may use ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses, for measuring the O_2 content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10–1981 incorporated by reference, see 40 CFR 60.17

[c] You may use EPA Method 18 of 40 CFR part 60, appendix A–6, provided that you conduct an adequate pre-survey 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. ASTM D6420–99(2004) incorporated by reference; see 40 CFR 60.17.

[e] Incorporated by reference; see 40 CFR 60.17.

■ 22. Amend appendix A–1 to part 60 as follows:

■ a. By amending Method 1 as follows:

■ i. By revising Figure 1–1 in section 17.

■ ii. By adding Figure 1–2 to section 17.

■ b. By amending Method 2 as follows:

■ i. By revising section 8.1, the note at the end of 10.1.1, and sections 10.4, 12.6, and 12.7.

■ ii. By removing the definition for Ts(abs) in section 12.1.

■ iii. By adding a definition for Ts(abavg) in alphabetical order to section 12.1.

■ c. By revising Method 2A, sections 10.3 and 12.2.

■ d. By revising Method 2B, section 12.1.

■ e. By revising Method 2D, section 10.4.

Appendix A–1 to Part 60—Test Methods 1 Through 2F

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Method 1—Sample and Velocity Traverses From Stationary Sources

* * * * *

17.0 * * *

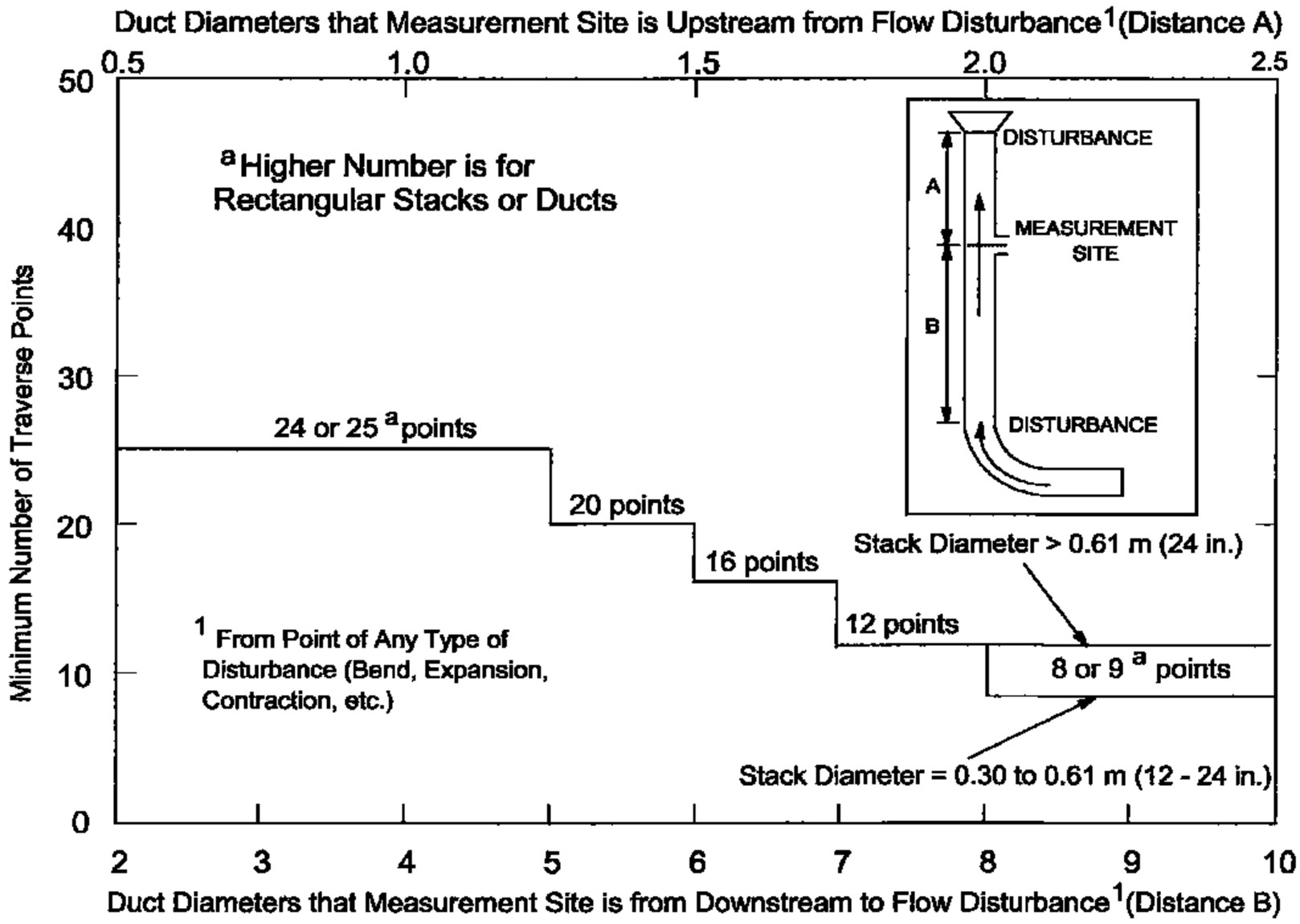

Figure 1-1. Minimum number of traverse points for particulate traverses

* * * * *

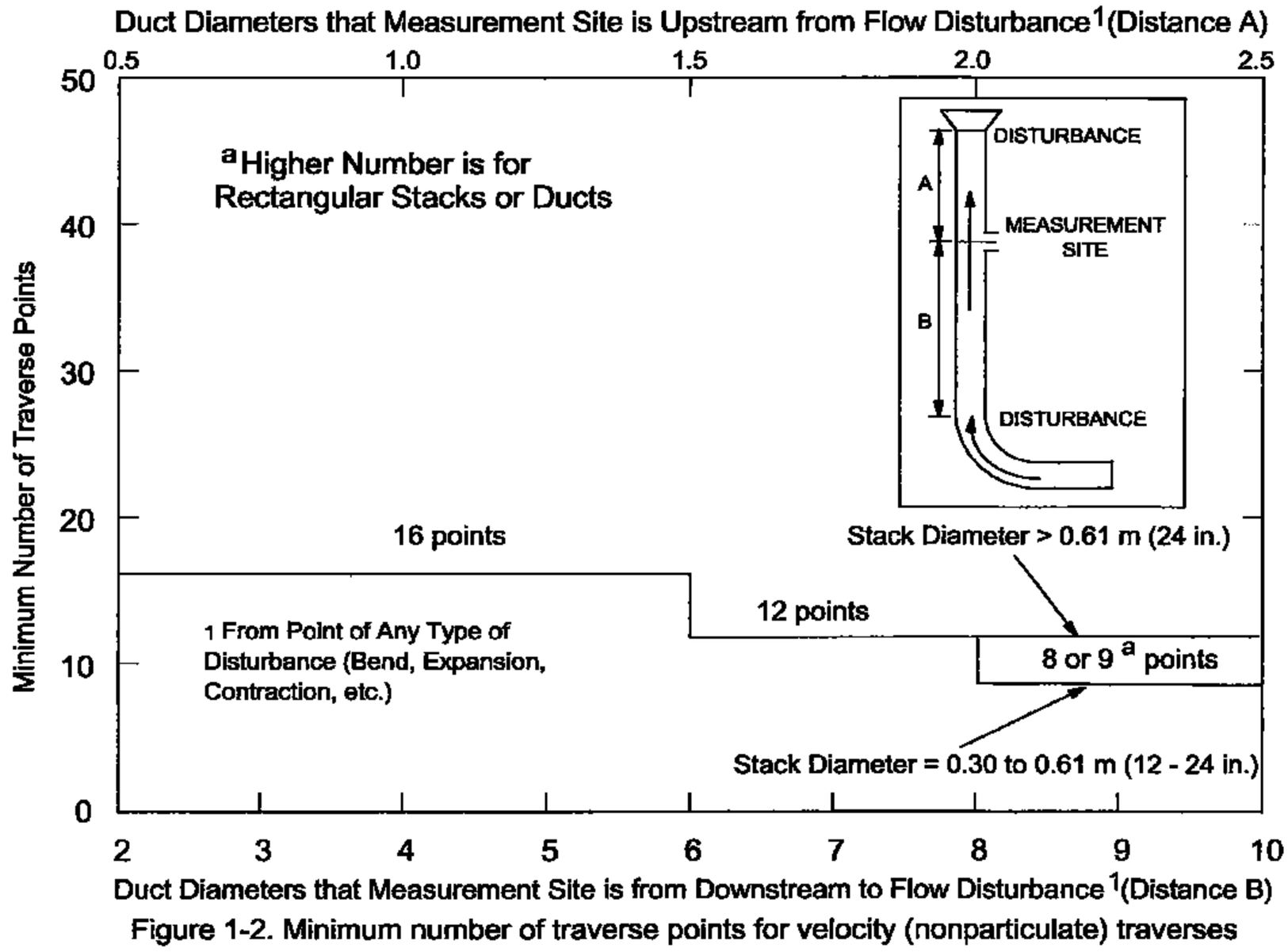

Figure 1-2. Minimum number of traverse points for velocity (nonparticulate) traverses

* * * * *

Method 2—Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)

* * * * *

8.1 Set up the apparatus as shown in Figure 2–1. Capillary tubing or surge tanks installed between the manometer and pitot tube may be used to dampen ΔP fluctuations. It is recommended, but not required, that a pretest leak-check be conducted as follows: (1) blow through the pitot impact opening until at least 7.6 cm (3.0 in.) H_2O velocity head registers on the manometer; then, close off the impact opening. The pressure shall remain stable (±2.5 mm H_2O, ±0.10 in. H_2O) for at least 15 seconds; (2) do the same for the static pressure side, except using suction to obtain the minimum of 7.6 cm (3.0 in.) H_2O. Other leak-check procedures, subject to the approval of the Administrator, may be used.

* * * * *

10.1.1 * * *

Note: Do not use a Type S pitot tube assembly that is constructed such that the impact pressure opening plane of the pitot tube is below the entry plane of the nozzle (see Figure 2–7B).

* * * * *

10.3 Barometer. Calibrate the barometer used against a mercury barometer or NIST-traceable barometer prior to the field test.

* * * * *

10.4 Barometer. Calibrate the barometer used against a mercury barometer or NIST-traceable barometer prior to each field test.

* * * * *

12.1 Nomenclature

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$T_{s(abavg)}$ = Average absolute stack temperature, °K (°R).
= 273 + T_s for metric units,
= 460 + T_s for English units.

* * * * *

12.2 Test Meter Calibration Coefficient.

12.6 Average Stack Gas Velocity.

$$V_s = K_p\, C_p \left[\frac{\sum_{i=1}^{n}\sqrt{\Delta p_i}}{n}\right]\sqrt{\frac{T_{s(abavg)}}{P_s\, M_s}} \qquad \text{Eq. 2-7}$$

Where:

$$K_p = 34.97\,\frac{m}{\sec}\left[\frac{(g/g-mole)(mm\ Hg)}{(^{\circ}K)(mm\ H_2O)}\right]^{1/2} \qquad \textit{Metric}$$

$$= 85.49\,\frac{ft}{\sec}\left[\frac{(lb/lb-mole)(in.\ Hg)}{(^{\circ}R)(in.\ H_2O)}\right]^{1/2} \qquad \textit{English}$$

12.7 Average Stack Gas Dry Volumetric Flow Rate.

$$Q = 3600(1 - B_{ws})v_s A\left[\frac{T_{std}P_s}{T_{s(abavg)}P_{std}}\right] \qquad Eq.2-8$$

* * * * *

Method 2A—Direct Measurement of Gas Volume Through Pipes and Small Ducts

* * * * *

$$Y_m = \frac{(V_{rf} - V_{ri})P_b\, T_{m(abs)}}{(V_{mf} - V_{mi})(P_b + P_g)T_{r(abs)}} \qquad \text{Eq. 2A-1}$$

* * * * *

Method 2B—Determination of Exhaust Gas Volume Flow Rate From Gasoline Vapor Incinerators

* * * * *

12.1 Nomenclature.

CO_e = Mean carbon monoxide concentration in system exhaust, ppm.
$(CO_2)_a$ = Ambient carbon dioxide concentration, ppm (if not measured during the test period, may be assumed to equal 380 ppm).
$(CO_2)_e$ = Mean carbon dioxide concentration in system exhaust, ppm.
HC_e = Mean organic concentration in system exhaust as defined by the calibration gas, ppm.
Hc_i = Mean organic concentration in system inlet as defined by the calibration gas, ppm.
K_e = Hydrocarbon calibration gas factor for the exhaust hydrocarbon analyzer, unitless [equal to the number of carbon atoms per molecule of the gas used to calibrate the analyzer (2 for ethane, 3 for propane, etc.)].
K_i = Hydrocarbon calibration gas factor for the inlet hydrocarbon analyzer, unitless.
V_{es} = Exhaust gas volume, m^3.
V_{is} = Inlet gas volume, m^3.
Q_{es} = Exhaust gas volume flow rate, m^3/min.
Q_{is} = Inlet gas volume flow rate, m^3/min.
θ = Sample run time, min.
S = Standard conditions: 20° C, 760 mm Hg.

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Method 2D—Measurement of Gas Volume Flow Rates in Small Pipes and Ducts

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10.4 Barometer. Calibrate the barometer used against a mercury barometer or NIST-traceable barometer prior to the field test.

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■ 23. Amend appendix A–2 to part 60 as follows:

■ a. By revising Method 3A, section 7.1.

■ b. By amending Method 3C as follows:

■ i. By revising section 7.1.

■ ii. By adding section 7.3.

Appendix A–2 to Part 60—Test Methods 2G Through 3C

* * * * *

Method 3A—Determination of Oxygen and Carbon Dioxide Concentrations in Emissions From Stationary Sources (Instrumental Analyzer Procedure)

* * * * *

7.1 Calibration Gas. *What calibration gases do I need?* Refer to Section 7.1 of Method 7E for the calibration gas requirements. Example calibration gas mixtures are listed below. Pre-cleaned or scrubbed air may be used for the O_2 high-calibration gas provided it does not contain other gases that interfere with the O_2 measurement.

(a) CO_2 in Nitrogen (N_2).
(b) CO_2/SO_2 gas mixture in N_2.
(c) O_2/SO_2 gas mixture in N_2.
(d) $O_2/CO_2/SO_2$ gas mixture in N_2.
(e) CO_2/NO_X gas mixture in N_2.
(f) $CO_2/SO_2/NO_X$ gas mixture in N_2.

The tests for analyzer calibration error and system bias require high-, mid-, and low-level gases.

* * * * *

Method 3C—Determination of Carbon Dioxide, Methane, Nitrogen, and Oxygen from Stationary Sources

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7.1 Nomenclature.

B_w = Moisture content in the sample, fraction.
C_{N2} = Measured N_2 concentration (by Method 3C), fraction.
C_{N2Corr} = Measured N_2 concentration corrected only for dilution, fraction.
C_t = Calculated NMOC concentration, ppmv C equivalent.
C_{tm} = Measured NMOC concentration, ppmv C equivalent.
P_b = Barometric pressure, mm Hg.
P_t = Gas sample tank pressure after sampling, but before pressurizing, mm Hg absolute.
P_{tf} = Final gas sample tank pressure after pressurizing, mm Hg absolute.
P_{ti} = Gas sample tank pressure after evacuation, mm Hg absolute.
P_w = Vapor pressure of H_2O (from Table 25C–1), mm Hg.
r = Total number of analyzer injections of sample tank during analysis (where j = injection number, 1 . . . r).
R = Mean calibration response factor for specific sample component, area/ppm.
T_t = Sample tank temperature at completion of sampling, °K.
T_{ti} = Sample tank temperature before sampling, °K.
T_{tf} = Sample tank temperature after pressurizing, °K.

* * * * *

7.3 Measured N_2 Concentration Correction. Calculate the reported N_2 correction for Method 25–C using Eq. 3C–4. If oxygen is determined in place of N_2, substitute the oxygen concentration for the nitrogen concentration in the equation.

$$C_{N_2Corr} = \frac{\frac{P_{tf}}{T_{tf}}}{\frac{P_t}{T_t} - \frac{P_{ti}}{T_{ti}}}(C_{N_2}) \quad Eq.\ 3C-4$$

* * * * *

■ 24. Amend appendix A–3 to part 60 as follows:

■ a. By revising Method 4, sections 9.1 and 16.0.

■ b. Amend Method 5 as follows:

■ i. By revising sections 6.1.1.5, 6.1.1.6, 6.1.1.7, 6.1.1.9, 7.1.3, 8.1, 8.3.4, 8.5, 8.5.6, 8.7.3, 8.7.5, 10.3.3, 10.5, 10.6.

■ ii. By removing section 7.1.5.

■ iii. By revising Equation 5–13 in section 16.2.3.3.

■ iv. By adding section 16.3.

■ v. By adding reference 13 to section 17.0.

■ c. By revising Method 5A, section 8.1.

■ d. By amending Method 5E as follows:

■ i. By redesignating sections 16.0 and 17.0 as sections 17.0 and 18.0, respectively.

■ ii. By adding a new section 16.0.

■ e. By amending Method 5H as follows:

■ i. By revising section 12.1.

■ ii. By adding section 12.15.

■ iii. By redesignating sections 16.0 and 17.0 as sections 17.0 and 18.0, respectively.

■ iv. By adding a new section 16.

Appendix A–3 to Part 60—Test Methods 4 Through 5I

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Method 4—Determination of Moisture Content in Stack Gases

* * * * *

9.1 Miscellaneous Quality Control Measures.

Section	Quality control measure	Effect
Section 8.1.1.4	Leak rate of the sampling system cannot exceed four percent of the average sampling rate or 0.00057 m^3/min (0.020 cfm).	Ensures the accuracy of the volume of gas sampled. (Reference Method).
Section 8.2.1	Leak rate of the sampling system cannot exceed two percent of the average sampling rate.	Ensures the accuracy of the volume of gas sampled. (Approximation Method).

* * * * *

16.0 Alternative Procedures

16.1 The procedure described in Method 5 for determining moisture content is an acceptable alternative to Method 4.

16.2 The procedures in Method 6A for determining moisture is an acceptable alternative to Method 4.

16.3 Method 320 is an acceptable alternative to Method 4 for determining moisture.

16.4 Using F-factors to determine moisture is an acceptable alternative to Method 4 for a combustion stack not using a scrubber. If this option is selected, calculate the moisture content as follows:

$B_{WS} - B_H + B_A + B_F$

Where:

B_A = Mole fraction of moisture in the ambient air.

$$= \frac{\%RH}{100\ P_{bar}\left[10^{\left(6.6912-\left(\frac{2144}{T+390.86}\right)\right)}\right]}$$

B_F = Mole fraction of moisture from free water in the fuel.

$$B_{fw} = \left[\frac{0.0036\ W^2 + 0.075\ W}{100}\right]\left[\frac{20.9 - O_2}{20.9}\right]$$

B_H = Mole fraction of moisture from the hydrogen in the fuel.

$$B_H = \left(1 - \frac{F_d}{F_w}\right)\frac{(20.9 - O_2)}{20.9}$$

B_{ws} = Mole fraction of moisture in the stack gas.
F_d = Volume of dry combustion components per unit of heat content at 0 percent oxygen, dscf/10^6 Btu (scm/J). See Table 19–2 in Method 19.
F_W = Volume of wet combustion components per unit of heat content at 0 percent oxygen, wet scf/10^6 Btu (scm/J). See Table 19–2 in Method 19.
%RH = Percent relative humidity (calibrated hydrometer acceptable), percent.
P_{Bar} = Barometric pressure, in. Hg.
T = Ambient temperature, °F.
W = Percent free water by weight, percent.
O_2 = Percent oxygen in stack gas, dry basis, percent.

* * * * *

Method 5—Determination of Particulate Matter Emissions From Stationary Sources

* * * * *

6.1.1.5 Filter Holder. Borosilicate glass, with a glass or Teflon frit filter support and a silicone rubber gasket. Other materials of construction (e.g., stainless steel or Viton) may be used, subject to the approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The holder shall be attached immediately at the outlet of the probe (or cyclone, if used).

6.1.1.6 Filter Heating System. Any heating system capable of monitoring and maintaining temperature around the filter shall be used to ensure the sample gas temperature exiting the filter of 120 ± 14 °C (248 ± 25 °F) during sampling or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. The monitoring and regulation of the temperature around the filter may be done with the filter temperature sensor or another temperature sensor.

6.1.1.7 Filter Temperature Sensor. A temperature sensor capable of measuring temperature to within ±3 °C (5.4 °F) shall be installed so that the sensing tip of the temperature sensor is in direct contact with the sample gas exiting the filter. The sensing tip of the sensor may be encased in glass, Teflon, or metal and must protrude at least ½ in. into the sample gas exiting the filter. The filter temperature sensor must be monitored and recorded during sampling to ensure a sample gas temperature exiting the filter of 120 ± 14 °C (248 ± 25 °F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application.

* * * * *

6.1.1.9 Metering System. Vacuum gauge, leak-free pump, calibrated temperature sensors (rechecked at at least one point after each test), dry gas meter (DGM) capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 5–1. Alternatively, an Isostack metering system may be used if all Method 5 calibrations are performed, with the exception of those related to ΔH@ in Section 9.2.1, wherein the sample flow rate system shall be calibrated in lieu of ΔH@ and shall not deviate by more than 5 percent. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall allow periodic checks of isokinetic rates.

* * * * *

7.1.3 Water. When analysis of the material caught in the impingers is required, deionized distilled water [to conform to ASTM D1193–77 or 91 Type 3 (incorporated by reference—see § 60.17)] with at least <0.001 percent residue shall be used or as specified in the applicable method requiring analysis of the water. Run reagent blanks prior to field use to eliminate a high blank on test samples.

* * * * *

8.1 Pretest Preparation. It is suggested that sampling equipment be maintained according to the procedures described in APTD–0576. Alternative mercury-free thermometers may be used if the thermometers are at a minimum equivalent in terms of performance or suitably effective for the specific temperature measurement application.

* * * * *

8.3.4 Set up the train as shown in Figure 5–1 ensuring that the connections are leak-tight. Subject to the approval of the Administrator, a glass cyclone may be used between the probe and filter holder when the total particulate catch is expected to exceed 100 mg or when water droplets are present in the stack gas.

* * * * *

8.5 Sampling Train Operation. During the sampling run, maintain an isokinetic sampling rate (within 10 percent of true isokinetic unless otherwise specified by the Administrator) and a sample gas temperature through the filter of 120 ± 14 °C (248 ± 25 °F) or such other temperature as specified by

an applicable subpart of the standards or approved by the Administrator.

* * * * *

8.5.6 During the test run, make periodic adjustments to keep the temperature around the filter holder at the proper level to maintain the sample gas temperature exiting the filter; add more ice and, if necessary, salt to maintain a temperature of less than 20 °C (68 °F) at the condenser/silica gel outlet. Also, periodically check the level and zero of the manometer.

* * * * *

8.7.3 Before moving the sample train to the cleanup site, remove the probe from the sample train and cap the open outlet of the probe. Be careful not to lose any condensate that might be present. Cap the filter inlet where the probe was fastened. Remove the umbilical cord from the last impinger, and cap the impinger. If a flexible line is used between the first impinger or condenser and the filter holder, disconnect the line at the filter holder, and let any condensed water or liquid drain into the impingers or condenser. Cap off the filter holder outlet and impinger inlet. Either ground-glass stoppers, plastic caps, or serum caps may be used to close these openings.

* * * * *

8.7.5 Save a portion of the acetone used for cleanup as a blank. From each storage container of acetone used for cleanup, save 200 ml and place in a glass sample container labeled "acetone blank." To minimize any particulate contamination, rinse the wash bottle prior to filling from the tested container.

* * * * *

10.3.3 Acceptable Variation in Calibration Check. If the DGM coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (*i.e.*, before or after) gives the lower value of total sample volume.

* * * * *

10.5 Temperature Sensors. Use the procedure in Section 10.3 of Method 2 to calibrate in-stack temperature sensors. Dial thermometers, such as are used for the DGM and condenser outlet, shall be calibrated against mercury-in-glass thermometers. An alternative mercury-free NIST-traceable thermometer may be used if the thermometer is, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application. As an alternative, the following single-point calibration procedure may be used. After each test run series, check the accuracy (and, hence, the calibration) of each thermocouple system at ambient temperature, or any other temperature, within the range specified by the manufacturer, using a reference thermometer (either ASTM reference thermometer or a thermometer that has been calibrated against an ASTM reference thermometer). The temperatures of the thermocouple and reference thermometers shall agree to within ±2 °F.

10.6 Barometer. Calibrate against a mercury barometer or NIST-traceable barometer prior to the field test. Alternatively, barometric pressure may be obtained from a weather report that has been adjusted for the test point (on the stack) elevation.

* * * * *

16.2.3.3 * * *

$$V_{cr(std)} = K' \frac{P_{bar}\theta}{\sqrt{T_{amb}}} \qquad \text{Eq. 5-13}$$

* * * * *

16.3 Alternative Post-Test Metering System Calibration. The following procedure may be used as an alternative to the post-test calibration described in Section 10.3.2. This alternative procedure does not detect leakages between the inlet of the metering system and the dry gas meter. Therefore, two steps must be included to make it an equivalent alternative:

(1) The metering system must pass the post-test leak-check from either the inlet of the sampling train or the inlet of the metering system. Therefore, if the train fails the former leak-check, another leak-check from the inlet of the metering system must be conducted;

(2) The metering system must pass the leak-check of that portion of the train from the pump to the orifice meter as described in Section 8.4.1.

16.3.1 After each test run, do the following:

16.3.1.1 Ensure that the metering system has passed the post-test leak-check. If not, conduct a leak-check of the metering system from its inlet.

16.3.1.2 Conduct the leak-check of that portion of the train from the pump to the orifice meter as described in Section 10.3.1.1.

16.3.1.3 Calculate Y_{qa} for each test run using the following equation:

$$Y_{qa} = \frac{\theta}{V_m}\sqrt{\frac{0.0319T_m}{\Delta H@\left(P_{bar} + \frac{\Delta H_{avg}}{13.6}\right)}}\left(\frac{29}{M_d}\right)\left(\sqrt{\Delta H}\right)_{avg} \qquad \text{Eq. 5-15}$$

Where:

Y_{qa} = Dry gas meter calibration check value, dimensionless.

0.0319 = (29.92/528) (0.75)^2 (in. Hg/°R) cfm^2.

$\Delta H@$ = Orifice meter calibration coefficient, in. H_2O.

M_d = Dry molecular weight of stack gas, lb/lb-mole.

29 = Dry molecular weight of air, lb/lb-mole.

16.3.2 After each test run series, do the following:

16.3.2.1 Average the three or more Y_{qa}'s obtained from the test run series and compare this average Y_{qa} with the dry gas meter calibration factor Y. The average Y_{qa} must be within 5 percent of Y.

16.3.2.2 If the average Y_{qa} does not meet the 5 percent criterion, recalibrate the meter over the full range of orifice settings as detailed in Section 10.3.1. Then follow the procedure in Section 10.3.3.

17.0 * * *

13. Shigehara, Roger T., P.G. Royals, and E.W. Steward. "Alternative Method 5 Post-Test Calibration." Entropy Incorporated, Research Triangle Park, NC 27709.

* * * * *

Method 5A—Determination of Particulate Matter Emissions From the Asphalt Processing and Asphalt Roofing Industry

* * * * *

8.1 Pretest Preparation. Unless otherwise specified, maintain and calibrate all components according to the procedure described in APTD–0576, "Maintenance, Calibration, and Operation of Isokinetic Source-Sampling Equipment" (Reference 3 in Method 5, Section 17.0). Alternative mercury-free thermometers may be used if the thermometers are, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application.

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Method 5E—Determination of Particulate Matter Emissions From the Wool Fiberglass Insulation Manufacturing Industry

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16.0 Alternative Procedures

16.1 Total Organic Carbon Analyzer. Tekmar-Dohrmann analyzers using the single injection technique may be used as an alternative to Rosemount Model 2100A analyzers.

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Method 5H—Determination of Particulate Matter Emissions From Wood Heaters From a Stack Location

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12.1 Nomenclature.

A = Sample flow rate adjustment factor.
BR = Dry wood burn rate, kg/hr (lb/hr), from Method 28, Section 8.3.
B_{ws} = Water vapor in the gas stream, proportion by volume.
C_i = Tracer gas concentration at inlet, ppmv.
C_o = Tracer gas concentration at outlet, ppmv.
C_s = Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).
E = Particulate emission rate, g/hr (lb/hr).
ΔH = Average pressure differential across the orifice meter (see Figure 5H–1), mm H_2O (in. H_2O).
L_a = Maximum acceptable leakage rate for either a post-test leak-check or for a leak-check following a component change; equal to 0.00057 cmm (0.020 cfm) or 4 percent of the average sampling rate, whichever is less.
L_i = Individual leakage rate observed during the leak-check conducted before a component change, cmm (cfm).
L_p = Leakage rate observed during the post-test leak-check, cmm (cfm).
m_n = Total amount of particulate matter collected, mg.
M_a = Mass of residue of solvent after evaporation, mg.
N_C = Grams of carbon/gram of dry fuel (lb/lb), equal to 0.0425.
N_T = Total dry moles of exhaust gas/kg of dry wood burned, g-moles/kg (lb-moles/lb).
PR = Percent of proportional sampling rate.
P_{bar} = Barometric pressure at the sampling site, mm Hg (in.Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in.Hg).
Q_i = Gas volumetric flow rate at inlet, cfm (l/min).
Q_o = Gas volumetric flow rate at outlet, cfm (l/min).

* * * * *

12.15 Alternative Tracer Gas Flow Rate Determination.

$$Q_o = \frac{Q_I \times C_i}{C_o} \quad Eq.\ 5H-10$$

Note: This gives Q for a single instance only. Repeated multiple determinations are needed to track temporal variations. Very small variations in Q_i, C_i, or C_o may give very large variations in Q_o.

* * * * *

16.0 Alternative Procedures

16.1 Alternative Stack Gas Volumetric Flow Rate Determination (Tracer Gas).

16.1.1 Apparatus.

16.1.1.1 Tracer Gas Injector System. This is to inject a known concentration of tracer gas into the stack. This system consists of a cylinder of tracer gas, a gas cylinder regulator, a stainless steel needle valve or a flow controller, a nonreactive (stainless steel or glass) rotameter, and an injection loop to disperse the tracer gas evenly in the stack.

16.1.1.2 Tracer Gas Probe. A glass or stainless steel sampling probe.

16.1.1.3 Gas Conditioning System. A gas conditioning system is suitable for delivering a cleaned sample to the analyzer consisting of a filter to remove particulate and a condenser capable of lowering the dew point of the sample gas to less than 5 °C (40 °F). A desiccant such as anhydrous calcium sulfate may be used to dry the sample gas. Desiccants which react or absorb tracer gas or stack gas may not be used, e.g. silica gel absorbs CO_2.

16.1.1.4. Pump. An inert (i.e., stainless steel or Teflon head) pump to deliver more than the total sample required by the manufacturer's specifications for the analyzer used to measure the downstream tracer gas concentration.

16.1.1.5 Gas Analyzer. A gas analyzer is any analyzer capable of measuring the tracer gas concentration in the range necessary at least every 10 minutes. A means of controlling the analyzer flow rate and a device for determining proper sample flow rate shall be provided unless data is provided to show that the analyzer is insensitive to flow variations over the range encountered during the test. The gas analyzer needs to meet or exceed the following performance specifications:

Linearity	±1 percent of full scale.
Calibration Error.	≤2 percent of span.
Response Time	≤10 seconds.
Zero Drift (24 hour).	≤2 percent of full scale.
Span Drift (24 hour).	≤2 percent of full scale.
Resolution	≤0.5 percent of span.

16.1.1.6 Recorder (optional). To provide a permanent record of the analyzer output.

16.1.2 Reagents.

16.1.2.1 Tracer Gas. The tracer gas is sulfur hexafluoride in an appropriate concentration for accurate analyzer measurement or pure sulfur dioxide. The gas used must be nonreactive with the stack effluent and give minimal (<3 percent) interference to measurement by the gas analyzer.

16.1.3 Procedure. Select upstream and downstream locations in the stack or duct for introducing the tracer gas and delivering the sampled gas to the analyzer. The inlet location should be 8 or more duct diameters beyond any upstream flow disturbance. The outlet should be 8 or more undisturbed duct diameters from the inlet and 2 or more duct diameters from the duct exit. After installing the apparatus, meter a known concentration of the tracer gas into the stack at the inlet location. Use the gas sample probe and analyzer to show that no stratification of the tracer gas is found in the stack at the measurement locations. Monitor the tracer gas concentration from the outlet location and record the concentration at 10-minute intervals or more often at the option of the tester. A minimum of three measured intervals is recommended to determine the stack gas volumetric flow rate. Other statistical procedures may be applied for complete flow characterization and additional QA/QC.

* * * * *

■ 25. Amend appendix A–4 to part 60 as follows:

■ a. By revising Method 6, sections 10.2 and 10.4.

■ b. By revising Method 6C, sections 4.0 and 8.3.

■ c. By revising Method 7, sections 4.0, 10.2, and 10.3.

■ d. By revising Method 7A, sections 4.0 and 10.4.

■ e. By revising Method 7E, sections 6.1, 7.1.1, the introductory text in section 8.2.5, the introductory text in section 8.2.7, and the introductory text in section 16.2.2.

■ f. By revising Method 8, the definition for V_{soln} in section 12.1, and Figure 8–1 in section 17.0.

■ g. By revising Method 10, sections 6.2.5 and 8.4.2.

■ h. By revising Method 10A, sections 2.0, 8.2.1, 8.2.3, 11.1, 11.2, the introductory text in section 12.3, and 13.5.

■ i. By revising Method 10B, section 2.1, 6.2.3, the introductory text in section 12.2.

Appendix A–4 to Part 60—Test Methods 6 Through 10B

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Method 6—Determination of Sulfur Dioxide Emissions From Stationary Sources

* * * * *

10.2 Temperature Sensors. Calibrate against mercury-in-glass thermometers. An alternative mercury-free thermometer may be used if the thermometer is, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application.

* * * * *

10.4 Barometer. Calibrate against a mercury barometer or NIST-traceable barometer prior to the field test.

* * * * *

Method 6C—Determination of Sulfur Dioxide Emissions From Stationary Sources (Instrumental Analyzer Procedure)

* * * * *

4.0 Interferences

Refer to Section 4.0 of Method 7E.

* * * * *

8.3 *Interference Check.* You must follow the procedures of Section 8.2.7 of Method 7E

to conduct an interference check, substituting SO_2 for NO_X as the method pollutant. For dilution-type measurement systems, you must use the alternative interference check procedure in Section 16 and a co-located, unmodified Method 6 sampling train. Quenching in fluorescence analyzers must be evaluated and remedied unless a dilution system and ambient-level analyzer is used. This may be done by preparing the calibration gas to contain within 1 percent of the absolute oxygen and carbon dioxide content of the measured gas, preparing the calibration gas in air and using vendor nomographs, or by other acceptable means.

* * * * *

Method 7—Determination of Nitrogen Oxide Emissions From Stationary Sources

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4.0 Interferences

Biased results have been observed when sampling under conditions of high sulfur dioxide concentrations. At or above 2100 ppm SO_2, use five times the H_2O_2 concentration of the Method 7 absorbing solution. Laboratory tests have shown that high concentrations of SO_2 (about 2100 ppm) cause low results in Method 7 and 7A. Increasing the H_2O_2 concentration to five times the original concentration eliminates this bias. However, when no SO_2 is present, increasing the concentration by five times results in a low bias.

* * * * *

10.2 Barometer. Calibrate against a mercury barometer or NIST-traceable barometer prior to the field test.

10.3 Temperature Gauge. Calibrate dial thermometers against mercury-in-glass thermometers. An alternative mercury-free thermometer may be used if the thermometer is, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application.

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Method 7A—Determination of Nitrogen Oxide Emissions From Stationary Sources (Ion Chromatographic Method)

* * * * *

4.0 Interferences

Biased results have been observed when sampling under conditions of high sulfur dioxide concentrations. At or above 2100 ppm SO_2, use five times the H_2O_2 concentration of the Method 7 absorbing solution. Laboratory tests have shown that high concentrations of SO_2 (about 2100 ppm) cause low results in Method 7 and 7A. Increasing the H_2O_2 concentration to five times the original concentration eliminates this bias. However, when no SO_2 is present, increasing the concentration by five times results in a low bias.

* * * * *

10.4 Temperature Gauge. Calibrate dial thermometers against mercury-in-glass thermometers. An alternative mercury-free thermometer may be used if the thermometer is, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application.

* * * * *

Method 7E—Determination of Nitrogen Oxides Emissions From Stationary Sources (Instrumental Analyzer Procedure)

* * * * *

6.1 What do I need for the measurement system? You may use any equipment and supplies meeting the following specifications:

(1) Sampling system components that are not evaluated in the system bias or system calibration error test must be glass, Teflon, or stainless steel. Other materials are potentially acceptable, subject to approval by the Administrator.

(2) The interference, calibration error, and system bias criteria must be met.

(3) Sample flow rate must be maintained within 10 percent of the flow rate at which the system response time was measured.

(4) All system components (excluding sample conditioning components, if used) must maintain the sample temperature above the moisture dew point. Ensure minimal contact between any condensate and the sample gas. Section 6.2 provides example equipment specifications for a NO_X measurement system. Figure 7E–1 is a diagram of an example dry-basis measurement system that is likely to meet the method requirements and is provided as guidance. For wet-basis systems, you may use alternative equipment and supplies as needed (some of which are described in Section 6.2), provided that the measurement system meets the applicable performance specifications of this method.

* * * * *

7.1.1 High-Level Gas. This concentration is chosen to set the calibration span as defined in Section 3.4.

* * * * *

8.2.5 Initial System Bias and System Calibration Error Checks. Before sampling begins, determine whether the high-level or mid-level calibration gas best approximates the emissions and use it as the upscale gas. Introduce the upscale gas at the probe upstream of all sample conditioning components in system calibration mode. Record the time it takes for the measured concentration to increase to a value that is at least 95 percent or within 0.5 ppm (whichever is less restrictive) of a stable response for both the low-level and upscale gases. Continue to observe the gas concentration reading until it has reached a final, stable value. Record this value on a form similar to Table 7E–2.

* * * * *

8.2.7 Interference Check. Conduct an interference response test of the gas analyzer prior to its initial use in the field. If you have multiple analyzers of the same make and model, you need only perform this alternative interference check on one analyzer. You may also meet the interference check requirement if the instrument manufacturer performs this or a similar check on an analyzer of the same make and model of analyzer that you use and provides you with documented results. Analytical quenching must be evaluated and remedied unless a dilution system and ambient-level analyzer are used. The analyzer must be checked for quenching at concentrations of approximately 4 and 12 percent CO_2 at a mid-range concentration for each analyzer range which is commonly used. The analyzer must be rechecked after it has been repaired or modified or on another periodic basis.

* * *

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16.2.2 Bag Procedure. Perform the analyzer calibration error test to document the calibration (both NO and NO_X modes, as applicable). Fill a Tedlar or equivalent bag approximately half full with either ambient air, pure oxygen, or an oxygen standard gas with at least 19.5 percent by volume oxygen content. Fill the remainder of the bag with mid- to high-level NO in N_2 (or other appropriate concentration) calibration gas. (Note that the concentration of the NO standard should be sufficiently high enough for the diluted concentration to be easily and accurately measured on the scale used. The size of the bag should be large enough to accommodate the procedure and time required. Verify through the manufacturer that the Tedlar alternative is suitable for NO and make this verifed information available for inspection.)

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Method 8—Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions From Stationary Sources

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12.1 * * *

V_{soln} = Total volume of solution in which the sample is contained, 1000 ml for the SO_2 sample and 250 ml for the H_2SO_4 sample.

* * * * *

17.0 Tables, Diagrams, Flowcharts, and Validation Data

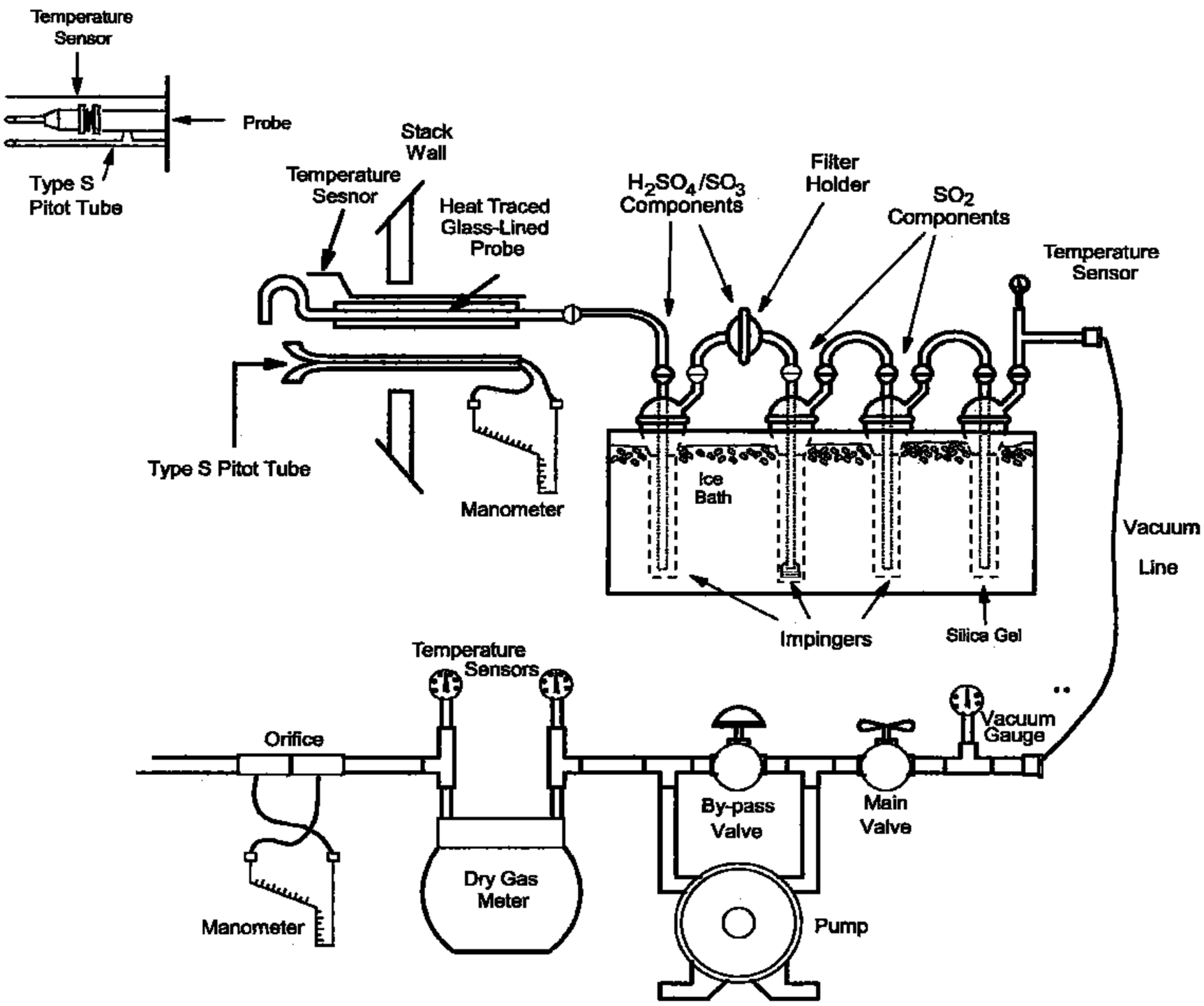

Figure 8-1. Sulfuric Acid Sampling Train

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Method 10—Determination of Carbon Monoxide Emissions From Stationary Sources

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6.2.5 Flexible Bag. Tedlar, or equivalent, with a capacity of 60 to 90 liters (2 to 3 ft^3). (Verify through the manufacturer that the Tedlar alternative is suitable for CO and make this verified information available for inspection.) Leak-test the bag in the laboratory before using by evacuating with a pump followed by a dry gas meter. When the evacuation is complete, there should be no flow through the meter. Gas tanks may be used in place of bags if the samples are analyzed within one week.

* * * * *

8.4.2 Integrated Sampling. Evacuate the flexible bag. Set up the equipment as shown in Figure 10–1 with the bag disconnected. Place the probe in the stack and purge the sampling line. Connect the bag, making sure that all connections are leak-free. Sample at a rate proportional to the stack velocity. If needed, the CO_2 content of the gas may be determined by using the Method 3 integrated sample procedures, or by weighing an ascarite CO_2 removal tube used and computing CO_2 concentration from the gas volume sampled and the weight gain of the tube. Data may be recorded on a form similar to Table 10–1. If a tank is used for sample collection, follow procedures similar to those in Sections 8.1.2, 8.2.3, 8.3, and 12.4 of Method 25 as appropriate to prepare the tank, conduct the sampling, and correct the measured sample concentration.

* * * * *

Method 10A—Determination of Carbon Monoxide Emissions in Certifying Continuous Emission Monitoring Systems at Petroleum Refineries

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2.0 Summary of Method

An integrated gas sample is extracted from the stack, passed through an alkaline permanganate solution to remove sulfur oxides and nitrogen oxides, and collected in a Tedlar or equivalent bag. (Verify through the manufacturer that the Tedlar alternative is suitable for NO and make this verified information available for inspection.) The CO concentration in the sample is measured spectrophotometrically using the reaction of CO with *p*-sulfaminobenzoic acid.

* * * * *

8.2.1 Evacuate the bag completely using a vacuum pump. Assemble the apparatus as shown in Figure 10A–1. Loosely pack glass wool in the tip of the probe. Place 400 ml of alkaline permanganate solution in the first two impingers and 250 ml in the third. Connect the pump to the third impinger, and follow this with the surge tank, rate meter,

and 3-way valve. Do not connect the bag to the system at this time.

* * * * *

8.2.3 Purge the system with sample gas by inserting the probe into the stack and drawing the sample gas through the system at 300 ml/min ±10 percent for 5 minutes. Connect the evacuated bag to the system, record the starting time, and sample at a rate of 300 ml/min for 30 minutes, or until the bag is nearly full. Record the sampling time, the barometric pressure, and the ambient temperature. Purge the system as described above immediately before each sample.

* * * * *

11.1 Assemble the system shown in Figure 10A–3, and record the information required in Table 10A–1 as it is obtained. Pipet 10.0 ml of the colorimetric reagent into each gas reaction bulb, and attach the bulbs to the system. Open the stopcocks to the reaction bulbs, but leave the valve to the bag closed. Turn on the pump, fully open the coarse-adjust flow valve, and slowly open the fine-adjust valve until the pressure is reduced to at least 40 mm Hg. Now close the coarse adjust valve, and observe the manometer to be certain that the system is leak-free. Wait a minimum of 2 minutes. If the pressure has increased less than 1 mm Hg, proceed as described below. If a leak is present, find and correct it before proceeding further.

11.2 Record the vacuum pressure (P_v) to the nearest 1 mm Hg, and close the reaction bulb stopcocks. Open the bag valve, and allow the system to come to atmospheric pressure. Close the bag valve, open the pump coarse adjust valve, and evacuate the system again. Repeat this fill/evacuation procedure at least twice to flush the manifold completely. Close the pump coarse adjust valve, open the bag valve, and let the system fill to atmospheric pressure. Open the stopcocks to the reaction bulbs, and let the entire system come to atmospheric pressure. Close the bulb stopcocks, remove the bulbs, record the room temperature and barometric pressure (P_{bar}, to nearest mm Hg), and place the bulbs on the shaker table with their main axis either parallel to or perpendicular to the plane of the table top. Purge the bulb-filling system with ambient air for several minutes between samples. Shake the samples for exactly 2 hours.

* * * * *

12.3 CO Concentration in the Bag. Calculate C_b using Equations 10A–2 and 10A–3. If condensate is visible in the bag, calculate B_w using Table 10A–2 and the temperature and barometric pressure in the analysis room. If condensate is not visible, calculate B_w using the temperature and barometric pressure at the sampling site.

* * *

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13.5 Stability. The individual components of the colorimetric reagent are stable for at least one month. The colorimetric reagent must be used within two days after preparation to avoid excessive blank correction. The samples in the bag should be stable for at least one week if the bags are leak-free.

* * * * *

Method 10B—Determination of Carbon Monoxide Emissions From Stationary Sources

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2.1 An integrated gas sample is extracted from the sampling point, passed through a conditioning system to remove interferences, and collected in a Tedlar or equivalent bag. (Verify through the manufacturer that the Tedlar alternative is suitable for NO and make this verifying information available for inspection.) The CO is separated from the sample by gas chromatography (GC) and catalytically reduced to methane (CH_4) which is determined by flame ionization detection (FID). The analytical portion of this method is identical to applicable sections in Method 25 detailing CO measurement.

* * * * *

6.2.3 Sample Injection System. Same as in Method 25, Section 6.3.1.4, equipped to accept a sample line from the bag.

* * * * *

12.2 CO Concentration in the Bag. Calculate C_b using Equations 10B–1 and 10B–2. If condensate is visible in the bag, calculate B_w using Table 10A–2 of Method 10A and the temperature and barometric pressure in the analysis room. If condensate is not visible, calculate B_w using the temperature and barometric pressure at the sampling site.

* * * * *

■ 26. Amend appendix A–5 to part 60 as follows:

■ a. By revising Method 11, sections 8.5 and 10.1.2.

■ b. Amend Method 12 as follows:

■ i. By revising section 16.1.

■ ii. By adding sections 16.4, 16.5, and 16.6.

■ c. By adding a sentence to the end of Method 14A, section 10.1.1.

Appendix A–5 to Part 60—Test Methods 11 Through 15A

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Method 11—Determination of Hydrogen Sulfide Content of Fuel Gas Streams in Petroleum Refineries

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8.5 Sample for at least 10 minutes. At the end of the sampling time, close the sampling valve, and record the final volume and temperature readings. Conduct a leak-check as described in Section 8.2. A yellow color in the final cadmium sulfate impinger indicates depletion of the absorbing solution. An additional cadmium sulfate impinger should be added for subsequent samples and the sample with yellow color in the final impinger should be voided.

* * * * *

10.1.2 Temperature Sensors. Calibrate against mercury-in-glass thermometers. An alternative mercury-free thermometer may be used if the thermometer is at a minimum equivalent in terms of performance or suitably effective for the specific temperature measurement application.

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Method 12—Determination of Inorganic Lead Emissions From Stationary Sources

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16.1 Simultaneous Determination of Particulate Matter and Lead Emissions. Method 12 may be used to simultaneously determine Pb provided:

(1) Acetone is used to remove particulate from the probe and inside of the filter holder as specified by Method 5,

(2) 0.1 N HNO_3 is used in the impingers,

(3) A glass fiber filter with a low Pb background is used, and

(4) The entire train contents, including the impingers, are treated and analyzed for Pb as described in Sections 8.0 and 11.0 of this method.

* * * * *

16.4 Inductively Coupled Plasma-Atomic Emission Spectrometry (ICP–AES) Analysis. ICP–AES may be used as an alternative to atomic absorption analysis provided the following conditions are met:

16.4.1 Sample collection, sample preparation, and analytical preparation procedures are as defined in the method except as necessary for the ICP–AES application.

16.4.2 The limit of quantitation for the ICP–AES must be demonstrated, and the sample concentrations reported should be no less than two times the limit of quantitation. The limit of quantitation is defined as ten times the standard deviation of the blank value. The standard deviation of the blank value is determined from the analysis of seven blanks. It has been reported that for mercury and those elements that form hydrides, a continuous-flow generator coupled to an ICP–AES offers detection limits comparable to cold vapor atomic absorption.

16.5 Inductively Coupled Plasma-Mass Spectrometry (ICP–MS) Analysis. ICP–MS may be used as an alternative to atomic absorption analysis.

16.6 Cold Vapor Atomic Fluorescence Spectrometry (CVAFS) Analysis. CVAFS may be used as an alternative to atomic absorption analysis.

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Method 14A—Determination of Total Fluoride Emissions From Selected Sources at Primary Aluminum Production Facilities

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10.1.1 * * * Allowable tolerances for Y and ΔH@ are given in Figure 5–5 of Method 5 of this appendix.

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■ 27. Amend appendix A–6 to part 60 as follows:

■ a. By revising Method 16A, section 1.2.

■ b. By revising Method 16C, sections 12.1 and 12.5.

■ c. By revising Method 18, sections 8.2.1.1.2, 8.2.1.4, 8.2.1.4.2, 16.1.1.12, 16.1.3.2, and the headings of figures 18–3 and 18–10.

■ d. By redesignating section 8.2.1.5.2.3 as section 8.2.1.5.2.2.

■ e. By adding a new section 8.2.1.5.2.3.

Appendix A–6 to Part 60—Test Methods 16 Through 18

* * * * *

Method 16A—Determination of Total Reduced Sulfur Emissions From Stationary Sources (Impinger Technique)

* * * * *

1.2 Applicability. This method is applicable for the determination of TRS emissions from recovery boilers, lime kilns, and smelt dissolving tanks at kraft pulp mills, reduced sulfur compounds (H_2S, carbonyl sulfide, and carbon disulfide) from sulfur recovery units at onshore natural gas processing facilities, and from other sources when specified in an applicable subpart of the regulations. The flue gas must contain at least 1 percent oxygen for complete oxidation of all TRS to SO_2. Note: If sources other than kraft pulp mills experience low oxygen levels in the emissions, the method results may be biased low.

* * * * *

Method 16C—Determination of Total Reduced Sulfur Emissions From Stationary Sources

* * * * *

12.1 Nomenclature.

ACE = Analyzer calibration error, percent of calibration span.
CD = Calibration drift, percent.
C_{Dir} = Measured concentration of a calibration gas (low, mid, or high) when introduced in direct calibration mode, ppmv.
C_{H2S} = Concentration of the system performance check gas, ppmv H_2S.
C_S = Measured concentration of the system performance gas when introduced in system calibration mode, ppmv H_2S.
C_V = Manufacturer certified concentration of a calibration gas (low, mid, or high), ppmv SO_2.
C_{SO2} = Unadjusted sample SO_2 concentration, ppmv.
C_{TRS} = Total reduced sulfur concentration corrected for system performance, ppmv.
DF = Dilution system (if used) dilution factor, dimensionless.
SP = System performance, percent.

* * * * *

12.5 TRS Concentration as SO_2. For each sample or test run, calculate the arithmetic average of SO_2 concentration values (e.g., 1-minute averages). Then calculate the sample TRS concentration by adjusting the average value of C_{SO2} for system performance using Equation 16C–4.

$$C_{TRS} = \frac{\overline{C_{SO2}}}{1 - \left|\overline{SP}\right|} \qquad \text{Eq. 16C-4}$$

* * * * .

Method 18—Measurement of Gaseous Organic Compound Emissions by Gas Chromatography

* * * * *

8.2.1.1.2 Sampling Procedure. To obtain a sample, assemble the sample train as shown in Figure 18–9. Leak-check both the bag and the container. Connect the vacuum line from the needle valve to the Teflon sample line from the probe. Place the end of the probe at the centroid of the stack or at a point no closer to the walls than 1 in., and start the pump. Set the flow rate so that the final volume of the sample is approximately 80 percent of the bag capacity. After allowing sufficient time to purge the line several times, connect the vacuum line to the bag, and evacuate until the rotameter indicates no flow. Then position the sample and vacuum lines for sampling, and begin the actual sampling, keeping the rate proportional to the stack velocity. As a precaution, direct the gas exiting the rotameter away from sampling personnel. At the end of the sample period, shut off the pump, disconnect the sample line from the bag, and disconnect the vacuum line from the bag container. Record the source temperature, barometric pressure, ambient temperature, sampling flow rate, and initial and final sampling time on the data sheet shown in Figure 18–10. Protect the bag and its container from sunlight. Record the time lapsed between sample collection and analysis, and then conduct the recovery procedure in Section 8.4.2.

* * * * *

8.2.1.4 Other Modified Bag Sampling Procedures. In the event that condensation is observed in the bag while collecting the sample and a direct interface system cannot be used, heat the bag during collection and maintain it at a suitably elevated temperature during all subsequent operations. (Note: Take care to leak-check the system prior to the dilutions so as not to create a potentially explosive atmosphere.) As an alternative, collect the sample gas, and simultaneously dilute it in the bag.

* * * * *

8.2.1.4.2 Second Alternative Procedure. Prefill the bag with a known quantity of inert gas. Meter the inert gas into the bag according to the procedure for the preparation of gas concentration standards of volatile liquid materials (Section 10.1.2.2), but eliminate the midget impinger section. Take the partly filled bag to the source, and meter the source gas into the bag through heated sampling lines and a heated flowmeter, or Teflon positive displacement pump. Verify the dilution factors before sampling each bag through dilution and analysis of gases of known concentration.

* * * * *

8.2.1.5.2.3 Analyze the two field audit samples as described in Section 9.2 by connecting each bag containing an audit gas mixture to the sampling valve. Calculate the results; record and report the data to the audit supervisor.

* * * * *

16.1.1.12 Flexible Bags. Tedlar or equivalent, 10- and 50-liter capacity, for preparation of standards. (Verify through the manufacturer that the Tedlar alternative is suitable for the compound of interest and make this verifying information available for inspection.)

* * * * *

16.1.3.2 Flexible Bag Procedure. Any leak-free plastic (e.g., Tedlar, Mylar, Teflon) or plastic-coated aluminum (e.g., aluminized Mylar) bag, or equivalent, can be used to obtain the pre-survey sample. Use new bags, and leak-check them before field use. In addition, check the bag before use for contamination by filling it with nitrogen or air and analyzing the gas by GC at high sensitivity. Experience indicates that it is desirable to allow the inert gas to remain in the bag about 24 hours or longer to check for desorption of organics from the bag. Follow the leak-check and sample collection procedures given in Section 8.2.1.

* * * * *

18.0 * * *

Figure 18–3. Preparation of Standards in Tedlar or Tedlar-Equlivalent Bags and Calibration Curve

* * * * *

Figure 18–10. Field Sample Data Sheet—Tedlar or Tedlar-Equivalent Bag Collection Method

* * * * *

■ 28. Amend appendix A–7 to part 60 as follows:
■ a. By amending Method 23 as follows:
■ i. By revising sections 2.2.7, 4.1.1.3, and 4.2.7.
■ ii. By adding and reserving section 8.0.
■ b. By revising Method 24, section 11.2.2.
■ c. By revising Method 25, section 7.1.3.
■ d. Amend Method 25C as follows:
■ i. By revising sections 6.1 and 12.1.
■ ii. By adding a new section 8.2.3.
■ e. By revising Method 25D, the first sentence in section 9.1.

Appendix A–7 to Part 60—Test Methods 19 Through 25E

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Method 23—Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans From Stationary Sources

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2.2.7 Storage Container. Air-tight container to store silica gel.

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4.1.1.3 Sample Train. It is suggested that all components be maintained according to the procedure described in APTD–0576. Alternative mercury-free thermometers may be used if the thermometers are, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application.

* * * * *

4.2.7 Silica Gel. Note the color of the indicating silica gel to determine if it has been completely spent and make a mention of its condition. Transfer the silica gel from the fifth impinger to its original container and seal. If a moisture determination is made, follow the applicable procedures in sections 8.7.6.3 and 11.2.3 of Method 5 to handle and weigh the silica gel. If moisture is not measured, the silica gel may be disposed.

* * * * *

8.0 [Reserved]

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Method 24—Determination of Volatile Matter Content, Water Content, Density, Volume Solids, and Weight Solids of Surface Coatings

* * * * *

11.2.2 Volatile Content. To determine total volatile content, use the apparatus and reagents described in ASTM D2369 (incorporated by reference; see § 60.17 for the approved versions of the standard), respectively, and use the following procedures:

* * * * *

Method 25—Determination of Total Gaseous Nonmethane Organic Emissions as Carbon

* * * * *

7.1.3 Filters. Glass fiber filters, without organic binder, exhibiting at least 99.95 percent efficiency (<0.05 percent penetration) on 0.3 micron dioctyl phthalate smoke particles. The filter efficiency test shall be conducted in accordance with ASTM Method D2986–71, 78, or 95a (incorporated by reference—see § 60.17). Test data from the supplier's quality control program are sufficient for this purpose.

* * * * *

Method 25C—Determination of Nonmethane Organic Compounds (NMOC) in MSW Landfill Gases

* * * * *

6.1 Sample Probe. Stainless steel, with the bottom third perforated. Teflon probe liners and sampling lines are also allowed. Non-perforated probes are allowed as long as they are withdrawn to create a gap equivalent to having the bottom third perforated. The sample probe must be capped at the bottom and must have a threaded cap with a sampling attachment at the top. The sample probe must be long enough to go through and extend no less than 0.9 m (3 ft) below the landfill cover. If the sample probe is to be driven into the landfill, the bottom cap should be designed to facilitate driving the probe into the landfill.

* * * * *

8.2.3 Driven Probes. Closed-point probes may be driven directly into the landfill in a single step. This method may not require backfilling if the probe is adequately sealed by its insertion. Unperforated probes that are inserted in this manner and withdrawn at a distance from a detachable tip to create an open space are also acceptable.

* * * * *

12.1 Nomenclature.

B_w = Moisture content in the sample, fraction.
C_{N2} = Reported N_2 concentration (C_{N2Corr} by Method 3C), fraction.
C_t = Calculated NMOC concentration, ppmv C equivalent.
C_{tm} = Measured NMOC concentration, ppmv C equivalent.
P_b = Barometric pressure, mm Hg.
P_t = Gas sample tank pressure after sampling, but before pressurizing, mm Hg absolute.
P_{tf} = Final gas sample tank pressure after pressurizing, mm Hg absolute.
P_{ti} = Gas sample tank pressure after evacuation, mm Hg absolute.
P_w = Vapor pressure of H_2O (from Table 25C–1), mm Hg.
r = Total number of analyzer injections of sample tank during analysis (where j=injection number, 1 . . . r).
T_t = Sample tank temperature at completion of sampling, °K.
T_{ti} = Sample tank temperature before sampling, °K.
T_{tf} = Sample tank temperature after pressurizing, °K.

* * * * *

Method 25D—Determination of the Volatile Organic Concentration of Waste Samples

* * * * *

9.1 Quality Control Samples. If audit samples are not available, prepare and analyze the two types of quality control samples (QCS) listed in Sections 9.1.1 and 9.1.2. * * *

* * * * *

■ 29. Amend appendix A–8 to part 60 as follows:
■ a. By amending Method 26 as follows:
■ i. By revising sections 6.1.1, 6.1.5, and 8.1.2.
■ ii. By redesignating sections 16.0 and 17.0 as sections 17.0 and 18.0, respectively.
■ iii. By adding a new section 16.0.
■ b. By revising Method 26A, sections 6.1.7, 8.1.5, and 8.1.6.
■ c. By amending Method 29 as follows:
■ i. By redesignating sections 16.0 and 17.0 as sections 17.0 and 18.0, respectively.
■ ii. By adding a new section 16.0.
■ d. By revising Method 30B, the introductory text to section 8.2.2.1, the note to section 8.2.4, the note to section 8.2.6.2, and sections 9.0, 10.3, 10.4, 11.3.

Appendix A–8 to Part 60—Text Methods 26 Through 30B

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Method 26—Determination of Hydrogen Halide and Halogen Emissions From Stationary Sources Non-Isokinetic Method

* * * * *

6.1.1 Probe. Borosilicate glass, approximately 3/8-in. (9-mm) I.D. with a heating system capable of maintaining a probe gas temperature during sampling between 120 and 134 °C (248 and 273 °F) to prevent moisture condensation; or Teflon where stack probes are below 210 °C. If HF is a target analyte, then preconditioning of new teflon components by heating should be considered to prevent potential HF outgassing. A Teflon-glass filter in a mat configuration should be installed to remove particulate matter from the gas stream.

* * * * *

6.1.5 Heating System. Any heating system capable of maintaining a temperature around the probe and filter holder between 120 and 134 °C (248 and 273 °F) during sampling, or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application.

* * * * *

8.1.2 Adjust the probe temperature and the temperature of the filter and the stopcock (i.e., the heated area in Figure 26–1) to a temperature sufficient to prevent water condensation. This temperature must be maintained between 120 and 134 °C (248 and 273 °F). The temperature should be monitored throughout a sampling run to ensure that the desired temperature is maintained. It is important to maintain a temperature around the probe and filter in this range since it is extremely difficult to purge acid gases off these components. (These components are not quantitatively recovered and, hence, any collection of acid gases on these components would result in potential undereporting of these emissions. The applicable subparts may specify alternative higher temperatures.)

* * * * *

16.0 Alternative Procedures

Method 26A. Method 26A, which uses isokinetic sampling equipment, is an acceptable alternative to Method 26.

* * * * *

Method 26A—Determination of Hydrogen Halide and Halogen Emissions From Stationary Sources—Isokinetic Method

* * * * *

6.1.7 Heating System. Any heating system capable of maintaining a temperature around the probe and filter holder between 120 and 134 °C (248 to 273 °F) during sampling, or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application.

* * * * *

8.1.5 Sampling Train Operation. Follow the general procedure given in Method 5, Section 8.5. It is important to maintain a temperature around the probe, filter (and cyclone, if used) between 120 and 134 °C (248 and 273 °F) since it is extremely difficult to purge acid gases off these components. (These components are not quantitatively recovered and hence any collection of acid gases on these components would result in potential undereporting these emissions. The applicable subparts may specify alternative higher temperatures.) For each run, record the data required on a data sheet such as the one shown in Method 5, Figure 5–3. If the condensate impinger becomes too full, it may be emptied, recharged with 50 ml of 0.1 N H2SO4, and replaced during the sample run. The condensate emptied must be saved and included in the measurement of the volume of moisture collected and included in the sample for analysis. The additional 50 ml of absorbing reagent must also be considered in calculating the moisture. Before the sampling train integrity is compromised by removing the impinger, conduct a leak-check as described in Method 5, Section 8.4.2.

8.1.6 Post-Test Moisture Removal (Optional). When the optional cyclone is included in the sampling train or when

liquid is visible on the filter at the end of a sample run even in the absence of a cyclone, perform the following procedure. Upon completion of the test run, connect the ambient air conditioning tube at the probe inlet and operate the train with the filter heating system between 120 and 134 °C (248 and 275 °F) at a low flow rate (e.g., ΔH = 1 in. H_2O) to vaporize any liquid and hydrogen halides in the cyclone or on the filter and pull them through the train into the impingers. After 30 minutes, turn off the flow, remove the conditioning tube, and examine the cyclone and filter for any visible liquid. If liquid is visible, repeat this step for 15 minutes and observe again. Keep repeating until the cyclone is dry.

* * * * *

Method 29—Determination of Metals Emissions From Stationary Sources

* * * * *

16.0 Alternative Procedures

16.1 Alternative Analyzer. Samples may also be analyzed by cold vapor atomic fluorescence spectrometry.

16.2 [Reserved].

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Method 30B—Determination of Total Vapor Phase Mercury Emissions From Coal-Fired Combustion Sources Using Carbon Sorbent Traps

* * * * *

8.2.2.1 Determination of Minimum Calibration Concentration or Mass. Based on your instrument's sensitivity and linearity, determine the calibration concentrations or masses that make up a representative low level calibration range. Verify that you are able to meet the multipoint calibration performance criteria in section 11.0 of this method. Select a calibration concentration or mass that is no less than 2 times the lowest concentration or mass in your calibration curve. The lowest point in your calibration curve must be at least 5, and preferably 10, times the Method Detection Limit (MDL), which is the minimum amount of the analyte that can be detected and reported. The MDL must be determined at least once for the analytical system using an MDL study such as that found in section 15.0 to Method 301 of appendix A to part 63 of this chapter.

* * * * *

8.2.4 * * *

Note to Section 8.2.4: For the purposes of relative accuracy testing of Hg monitoring systems under subpart UUUUU of part 63 of this chapter and Performance Specifications 12A and 12B in appendix B to this part, when the stack gas Hg concentration is expected to be very low (<0.5 μg/dscm), you may estimate the Hg concentration at 0.5 μg/dscm.

* * * * *

8.2.6.2 * * *

Note to Section 8.2.6.2: It is acceptable to perform the field recovery test concurrent with actual test runs (e.g., through the use of a quad probe). It is also acceptable to use the field recovery test runs as test runs for emissions testing or for the RATA of a Hg monitoring system under subpart UUUUU of part 63 of this chapter and Performance Specifications 12A and 12B in appendix B to this part, if certain conditions are met. To determine whether a particular field recovery test run may be used as a RATA run, subtract the mass of the Hg^0 spike from the total Hg mass collected in sections 1 and 2 of the spiked trap. The difference represents the mass of Hg in the stack gas sample. Divide this mass by the sample volume to obtain the Hg concentration in the effluent gas stream, as measured with the spiked trap. Compare this concentration to the corresponding Hg concentration measured with the unspiked trap. If the paired trains meet the relative deviation and other applicable data validation criteria in Table 9–1, then the average of the two Hg concentrations may be used as an emissions test run value or as the reference method value for a RATA run.

* * * * *

9.0 Quality Assurance and Quality Control

Table 9–1 summarizes the QA/QC performance criteria that are used to validate the Hg emissions data from Method 30B sorbent trap measurement systems.

TABLE 9–1—QUALITY ASSURANCE/QUALITY CONTROL CRITERIA FOR METHOD 30B

QA/QC test or specification	Acceptance criteria	Frequency	Consequences if not met
Gas flow meter calibration (At 3 settings or points).	Calibration factor (Y_i) at each flow rate must be within ±2% of the average value (Y).	Prior to initial use and when post-test check is not within ±5% of Y.	Recalibrate at 3 points until the acceptance criteria are met.
Gas flow meter post-test calibration check (Single-point).	Calibration factor (Y_i) must be within ±5% of the Y value from the most recent 3-point calibration.	After each field test. For mass flow meters, must be done on-site, using stack gas.	Recalibrate gas flow meter at 3 points to determine a new value of Y. For mass flow meters, must be done on-site, using stack gas. Apply the new Y value to the field test data.
Temperature sensor calibration	Absolute temperature measures by sensor within ±1.5% of a reference sensor.	Prior to initial use and before each test thereafter.	Recalibrate; sensor may not be used until specification is met.
Barometer calibration	Absolute pressure measured by instrument within ±10 mm Hg of reading with a mercury barometer or NIST traceable barometer.	Prior to initial use and before each test thereafter.	Recalibrate; instrument may not be used until specification is met.
Pre-test leak check	≤4% of target sampling rate	Prior to sampling	Sampling shall not commence until the leak check is passed.
Post-test leak check	≤4% of average sampling rate	After sampling	Sample invalidated.*
Analytical matrix interference test (wet chemical analysis, only).	Establish minimum dilution (if any) needed to eliminate sorbent matrix interferences.	Prior to analyzing any field samples; repeat for each type of sorbent used.	Field sample results not validated.
Analytical bias test	Average recovery between 90% and 110% for Hg^0 and $HgCl_2$ at each of the 2 spike concentration levels.	Prior to analyzing field samples and prior to use of new sorbent media.	Field samples shall not be analyzed until the percent recovery criteria has been met.
Multipoint analyzer calibration	Each analyzer reading within ±10% of true value *and* $r^2 \geq 0.99$.	On the day of analysis, before analyzing any samples.	Recalibrate until successful.
Analysis of independent calibration standard.	Within ±10% of true value	Following daily calibration, prior to analyzing field samples.	Recalibrate and repeat independent standard analysis until successful.

TABLE 9–1—QUALITY ASSURANCE/QUALITY CONTROL CRITERIA FOR METHOD 30B—Continued

QA/QC test or specification	Acceptance criteria	Frequency	Consequences if not met
Analysis of continuing calibration verification standard (CCVS).	Within ±10% of true value	Following daily calibration, after analyzing ≤10 field samples, and at end of each set of analyses.	Recalibrate and repeat independent standard analysis, reanalyze samples until successful, if possible; for destructive techniques, samples invalidated.
Test run total sample volume	Within ±20% of total volume sampled during field recovery test.	Each individual sample	Sample invalidated.
Sorbent trap section 2 breakthrough.	For compliance/emissions testing: ≤10% of section 1 Hg mass for Hg concentrations >1 µg/dscm; ≤20% of section 1 Hg mass for Hg concentrations ≤1 µg/dscm. ≤50% of section 1 Hg mass if the stack Hg concentration is ≤30% of the Hg concentration that is equivalent to the applicable emission limit. For relative accuracy testing: ≤10% of section 1 Hg mass for Hg concentrations >1 µg/dscm; ≤20% of section 1 Hg mass for Hg concentrations ≤1 µg/dscm and >0.5 µg/dscm; ≤50% of section 1 Hg mass for Hg concentrations ≤0.5 µg/dscm >0.1 µg/dscm; no criterion for Hg concentrations ≤0.1 µg/dscm (must meet all other QA/QC specifications).	Every sample	Sample invalidated.*
Paired sorbent trap agreement	≤10% Relative Deviation (RD) mass for Hg concentrations >1 µg/dscm; ≤20% RD or ≤0.2 µg/dscm absolute difference for Hg concentrations ≤1 µg/dscm.	Every run	Run invalidated.*
Sample analysis	Within valid calibration range (within calibration curve).	All Section 1 samples where stack Hg concentration is ≥0.02 µg/dscm except in case where stack Hg concentration is ≤30% of the applicable emission limit.	Reanalyze at more concentrated level if possible, samples invalidated if not within calibrated range.
Sample analysis	Within bounds of Hg^0 and $HgCl_2$ Analytical Bias Test.	All Section 1 samples where stack Hg concentration is ≥0.5 µg/dscm.	Expand bounds of Hg^0 and $HgCl_2$ Analytical Bias Test; if not successful, samples invalidated.
Field recovery test	Average recovery between 85% and 115% for Hg^0.	Once per field test	Field sample runs not validated without successful field recovery test.

*And data from the pair of sorbent traps are also invalidated.

* * * * *

10.3 Thermocouples and Other Temperature Sensors. Use the procedures and criteria in Section 10.3 of Method 2 in appendix A–1 to this part to calibrate in-stack temperature sensors and thermocouples. Dial thermometers shall be calibrated against mercury-in-glass thermometers or equivalent. Calibrations must be performed prior to initial use and before each field test thereafter. At each calibration point, the absolute temperature measured by the temperature sensor must agree to within ±1.5 percent of the temperature measured with the reference sensor, otherwise the sensor may not continue to be used.

10.4 Barometer. Calibrate against a mercury barometer or other NIST-traceable barometer as per Section 10.6 of Method 5 in appendix A–3 to this part. Calibration must be performed prior to initial use and before each test program, and the absolute pressure measured by the barometer must agree to within ±10 mm Hg of the pressure measured by the mercury or other NIST-traceable barometer, otherwise the barometer may not continue to be used.

* * * * *

11.3 Field Sample Analyses. Analyze the sorbent trap samples following the same procedures that were used for conducting the Hg^0 and $HgCl_2$ analytical bias tests. The individual sections of the sorbent trap and their respective components must be analyzed separately (i.e., section 1 and its components, then section 2 and its components). All sorbent trap section 1 sample analyses must be within the

calibrated range of the analytical system as specified in Table 9–1. For wet analyses, the sample can simply be diluted to fall within the calibrated range. However, for the destructive thermal analyses, samples that are not within the calibrated range cannot be re-analyzed. As a result, the sample cannot be validated, and another sample must be collected. It is strongly suggested that the analytical system be calibrated over multiple ranges so that thermally analyzed samples fall within the calibrated range. The total mass of Hg measured in each sorbent trap section 1 must also fall within the lower and upper mass limits established during the initial Hg^0 and $HgCl_2$ analytical bias test. If a sample is analyzed and found to fall outside of these limits, it is acceptable for an additional Hg^0 and $HgCl_2$ analytical bias test to be performed that now includes this level. However, some samples (e.g., the mass collected in trap section 2), may have Hg levels so low that it may not be possible to quantify them in the analytical system's calibrated range. Because a reliable estimate of these low-level Hg measurements is necessary to fully validate the emissions data, the MDL (see section 8.2.2.1 of this method) is used to establish the minimum amount that can be detected and reported. If the measured mass or concentration is below the lowest point in the calibration curve and above the MDL, the analyst must estimate the mass or concentration of the sample based on the analytical instrument response relative to an additional calibration standard at a concentration or mass between the MDL and the lowest point in the calibration curve. This is accomplished by establishing a response factor (e.g., area counts per Hg mass or concentration) and estimating the amount of Hg present in the sample based on the analytical response and this response factor.

Example: The analysis of a particular sample results in a measured mass above the MDL, but below the lowest point in the calibration curve which is 10 ng. An MDL of 1.3 ng Hg has been established by the MDL study. A calibration standard containing 5 ng of Hg is analyzed and gives an analytical response of 6,170 area counts, which equates to a response factor of 1,234 area counts/ng Hg. The analytical response for the sample is 4,840 area counts. Dividing the analytical response for the sample (4,840 area counts) by the response factor gives 3.9 ng Hg, which is the estimated mass of Hg in the sample.

* * * * *

■ 30. Amend appendix B to part 60 as follows:

■ a. By revising Performance Specification 3, section 13.2.

■ b. By revising Performance Specification 4, section 8.2.

■ c. By revising Performance Specification 4B, section 7.1.1.

■ d. By amending Performance Specification 7 as follows:

■ i. By revising section 8.4.

■ ii. By adding reference 5. to section 16.0.

■ e. By revising Performance Specification 11, sections 12.1(1) and (2).

■ f. By revising Performance Specification 12B, table 12B–1 in section 9.0 and section 12.8.3.

■ g. By revising Performance Specification 15, sections 11.1.1.4.2 and 11.1.1.4.3.

■ h. By revising Performance Specification 16, sections 6.1.7, 8.2.1, 9.1, 9.3, 9.4, 12.4, and 13.5.

Appendix B to Part 60—Performance Specifications

* * * * *

Performance Specification 3—Specifications and Test Procedures for O_2 and CO_2 Continuous Emission Monitoring Systems in Stationary Sources

* * * * *

13.2 CEMS Relative Accuracy Performance Specification. The RA of the CEMS must be no greater than 20 percent of the mean value of the reference method (RM) data. The results are also acceptable if the absolute value of the difference between the mean RM value and the mean CEMS value is less than or equal to 1.0 percent O_2 (or CO_2).

* * * * *

Performance Specification 4—Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources

* * * * *

8.2 Reference Methods. Unless otherwise specified in an applicable subpart of the regulation, Method 10, 10A, 10B or other approved alternative are the RM for this PS.

* * * * *

Performance Specification 4B—Specifications and Test Procedures for Carbon Monoxide and Oxygen Continuous Monitoring Systems in Stationary Sources

* * * * *

7.1.1 *Calculations.* Summarize the results on a data sheet. Average the differences between the instrument response and the certified cylinder gas value for each gas. Calculate the CE results for the CO monitor according to:

$$CE = | d/FS | \times 100 \quad (1)$$

Where d is the mean difference between the CEMS response and the known reference concentration, and FS is the span value. The CE for the O_2 monitor is the average percent O_2 difference between the O_2 monitor and the certified cylinder gas value for each gas.

* * * * *

Performance Specification 7—Specifications and Test Procedures for Hydrogen Sulfide Continuous Emission Monitoring Systems in Stationary Sources

* * * * *

8.4 Relative Accuracy Test Procedure.

8.4.1 Sampling Strategy for RM Tests, Number of RM Tests, Correlation of RM and CEMS Data, and Calculations. These are the same as that in PS–2, Sections 8.4.3 (except as specified below), 8.4.4, 8.4.5, and 8.4.6, respectively.

8.4.2 Reference Methods. Unless otherwise specified in an applicable subpart of the regulation, Methods 11, 15, and 16 may be used for the RM for this PS.

8.4.2.1 Sampling Time Per Run—Method 11. A sampling run, when Method 11 (integrated sampling) is used, shall consist of a single measurement for at least 10 minutes and 0.010 dscm (0.35 dscf). Each sample shall be taken at approximately 30-minute intervals.

8.4.2.2 Sampling Time Per Run—Methods 15 and 16. The sampling run shall consist of two injections equally spaced over a 30-minute period following the procedures described in the particular method. **Note:** Caution! Heater or non-approved electrical probes should not be used around explosive or flammable sources.

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16.0 * * *

5. Letter to RAMCON Environmental Corp. from Robert Kellam, December 27, 1992.

* * * * *

Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources

* * * * *

12.1 * * *

(1) Calculate the upscale drift (UD) using Equation 11–1:

$$UD = \frac{|R_{CEM} - R_U|}{FS} \times 100 \qquad \text{(Eq. 11-1)}$$

Where:

UD = The upscale (high-level) drift of your PM CEMS in percent,

R_{CEM} = The measured PM CEMS response to the upscale reference standard, and

R_U = The pre-established numerical value of the upscale reference standard.

FS= Full-scale value.

(2) Calculate the zero drift (ZD) using Equation 11–2:

$$ZD = \frac{|R_{CEM} - R_L|}{FS} \times 100 \qquad \text{(Eq. 11-2)}$$

Where:

ZD = The zero (low-level) drift of your PM CEMS in percent,

R_{CEM} = The measured PM CEMS response to the zero reference standard,

R_L = The pre-established numerical value of the zero reference standard, and

FS = Full-scale value.

* * * * *

Performance Specification 12B—Specifications and Test Procedures for Monitoring Total Vapor Phase Mercury Emissions from Stationary Sources Using a Sorbent Trap Monitoring System

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9.0 * * *

TABLE 12B–1—QA/QC CRITERIA FOR SORBENT TRAP MONITORING SYSTEMS

QA/QC test or specification	Acceptance criteria	Frequency	Consequences if not met
Pre-test leak check	≤4% of target sampling rate	Prior to monitoring	Monitoring must not commence until the leak check is passed.
Post-test leak check	≤4% of average sampling rate	After monitoring	Invalidate the data from the paired traps or, if certain conditions are met, report adjusted data from a single trap (see Section 12.8.3).
Ratio of stack gas flow rate to sample flow rate.	No more than 5% of the hourly ratios or 5 hourly ratios (whichever is less restrictive) may deviate from the reference ratio by more than ±25%.	Every hour throughout monitoring period.	Invalidate the data from the paired traps or, if certain conditions are met, report adjusted data from a single trap (see Section 12.8.3).
Sorbent trap section 2 breakthrough.	≤5% of Section 1 Hg mass ≤10% of Section 1 Hg mass if average Hg concentration is ≤0.5 µg/scm. No criterion when Hg concentration for trap less than 10% of the applicable emission limit (must meet all other QA/QC specifications).	Every sample	Invalidate the data from the paired traps or, if certain conditions are met, report adjusted data from a single trap (see Section 12.8.3).
Paired sorbent trap agreement	≤10% Relative Deviation (RD) if the average concentration is > 1.0 µg/m³. ≤20% RD if the average concentration is ≤1.0 µg/m³. Results also acceptable if absolute difference between concentrations from paired traps is ≤ 0.03 µg/m³.	Every sample	Either invalidate the data from the paired traps or report the results from the trap with the higher Hg concentration.
Spike Recovery Study	Average recovery between 85% and 115% for each of the 3 spike concentration levels.	Prior to analyzing field samples and prior to use of new sorbent media.	Field samples must not be analyzed until the percent recovery criteria have been met.
Multipoint analyzer calibration	Each analyzer reading within ± 10% of true value and $r^2 \geq 0.99$.	On the day of analysis, before analyzing any samples.	Recalibrate until successful.
Analysis of independent calibration standard.	Within ± 10% of true value	Following daily calibration, prior to analyzing field samples.	Recalibrate and repeat independent standard analysis until successful.
Spike recovery from section 3 of both sorbent traps.	75–125% of spike amount	Every sample	Invalidate the data from the paired traps or, if certain conditions are met, report adjusted data from a single trap (see Section 12.8.3).
Relative Accuracy	RA ≤ 20.0% of RM mean value; or if RM mean value ≤5.0 µg/scm, absolute difference between RM and sorbent trap monitoring system mean values ≤1.0 µg/scm.	RA specification must be met for initial certification.	Data from the system are invalid until a RA test is passed.

TABLE 12B–1—QA/QC CRITERIA FOR SORBENT TRAP MONITORING SYSTEMS—Continued

QA/QC test or specification	Acceptance criteria	Frequency	Consequences if not met
Gas flow meter calibration	An initial calibration factor (Y) has been determined at 3 settings; for mass flow meters, initial calibration with stack gas has been performed. For subsequent calibrations, Y within ±5% of average value from the most recent 3-point calibration.	At 3 settings prior to initial use and at least quarterly at one setting thereafter.	Recalibrate meter at 3 settings to determine a new value of Y.
Temperature sensor calibration	Absolute temperature measured by sensor within ± 1.5% of a reference sensor.	Prior to initial use and at least quarterly thereafter.	Recalibrate; sensor may not be used until specification is met.
Barometer calibration	Absolute pressure measured by instrument within ± 10 mm Hg of reading with a NIST-traceable barometer.	Prior to initial use and at least quarterly thereafter.	Recalibrate; instrument may not be used until specification is met.

* * * * *

12.8.3 For the routine, day-to-day operation of the monitoring system, when one of the two sorbent trap samples or sampling systems either: (a) Fails the post-monitoring leak check; or (b) has excessive section 2 breakthrough; or (c) fails to maintain the proper stack flow-to-sample flow ratio; or (d) fails to achieve the required section 3 spike recovery; or (e) is lost, broken, or damaged, provided that the other trap meets the acceptance criteria for all four of these QC specifications, the Hg concentration measured by the valid trap may be multiplied by a factor of 1.111 and then used for reporting purposes. Further, if both traps meet the acceptance criteria for all four of these QC specifications, but the acceptance criterion for paired trap agreement is not met, the owner or operator may report the higher of the two Hg concentrations measured by the traps, in lieu of invalidating the data from the paired traps.

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Performance Specification 15—Performance Specification for Extractive FTIR Continuous Emission Monitoring Systems in Stationary Sources

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11.1.1.4.2 RMs Using a Grab Sampling Technique. Synchronize the RM and FTIR CEM measurements as closely as possible. For a grab sampling RM, record the volume collected and the exact sampling period for each sample. Synchronize the FTIR CEM so that the FTIR measures a spectrum of a similar cell volume at the same time as the RM grab sample was collected. Measure at least five independent samples with both the FTIR CEM and the RM for each of the minimum nine runs. Compare the run concentration averages by using the relative accuracy analysis procedure in Performance Specification 2 of appendix B of 40 CFR part 60.

11.1.1.4.3 Continuous Emission Monitors as RMs. If the RM is a CEM, synchronize the sampling flow rates of the RM and the FTIR CEM. Each run is at least 1 hour long and consists of at least 10 FTIR CEM measurements and the corresponding 10 RM measurements (or averages). For the statistical comparison, use the relative accuracy analysis procedure in Performance Specification 2 of appendix B of 40 CFR part 60. If the RM time constant is < ½ the FTIR CEM time constant, brief fluctuations in analyte concentrations that are not adequately measured with the slower FTIR CEM time constant can be excluded from the run average along with the corresponding RM measurements. However, the FTIR CEM run average must still include at least 10 measurements over a 1-hour period.

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Performance Specification 16—Specifications and Test Procedures for Predictive Emission Monitoring Systems in Stationary Sources

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6.1.7 Sensor Location and Repair. We recommend you install sensors in an accessible location in order to perform repairs and replacements. Permanently-installed platforms or ladders may not be needed. If you install sensors in an area that is not accessible, you may be required to shut down the emissions unit to repair or replace a sensor. Conduct a new RATA after replacing a sensor that supplies a critical PEMS parameter if the new sensor provides a different output or scaling or changes the historical training dataset of the PEMS. Replacement of a non-critical sensor that does not cause an impact in the accuracy of the PEMS does not trigger a RATA. All sensors must be calibrated as often as needed but at least as often as recommended by the manufacturers.

* * * * *

8.2.1 Reference Methods. Unless otherwise specified in the applicable regulations, you must use the test methods in appendix A of this part for the RM test. Conduct the RM tests at three operating levels. The RM tests shall be performed at a low-load (or production) level between the minimum safe, stable load and 50 percent of the maximum level load, at the mid-load level (an intermediary level between the low and high levels), and at a high-load level between 80 percent and the maximum load. Alternatively, if practicable, you may test at three levels of the key operating parameter (e.g. selected based on a covariance analysis between each parameter and the PEMS output) equally spaced within the normal range of the parameter.

* * * * *

9.1 QA/QC Summary. Conduct the applicable ongoing tests listed below.

ONGOING QUALITY ASSURANCE TESTS

Test	PEMS regulatory purpose	Acceptability	Frequency
Sensor Evaluation	All		Daily.
RAA	Compliance	3-test avg ≤10% of simultaneous analyzer or RM average.	Each quarter except quarter when RATA performed.
RATA	All	Same as for RA in Sec. 13.1	Yearly in quarter when RAA not performed.
Bias Correction	All	If $d_{avg} \leq \|cc\|$	Bias test passed (no correction factor needed).
PEMS Training	All	If $F_{critical} \geq F$ r ≥0.8	Optional after initial and subsequent RATAs.

ONGOING QUALITY ASSURANCE TESTS—Continued

Test	PEMS regulatory purpose	Acceptability	Frequency
Sensor Evaluation Alert Test (optional).	All	See Section 6.1.8	After each PEMS training.

* * * * *

9.3 Quarterly Relative Accuracy Audits. In the first year of operation after the initial certification, perform a RAA consisting of at least three 30-minute portable analyzer or RM determinations each quarter a RATA is not performed. To conduct a RAA, follow the procedures in Section 8.2 for the relative accuracy test, except that only three sets of measurement data are required, and the statistical tests are not required. The average of the three or more portable analyzer or RM determinations must not exceed the limits given in Section 13.5. Report the data from all sets of measurement data. If a PEMS passes all quarterly RAAs in the first year and also passes the subsequent yearly RATA in the second year, you may elect to perform a single mid-year RAA in the second year in place of the quarterly RAAs. This option may be repeated, but only until the PEMS fails either a mid-year RAA or a yearly RATA. When such a failure occurs, you must resume quarterly RAAs in the quarter following the failure and continue conducting quarterly RAAs until the PEMS successfully passes both a year of quarterly RAAs and a subsequent RATA.

9.4 Yearly Relative Accuracy Test. Perform a minimum 9-run RATA at the normal operating level on a yearly basis in the quarter that the RAA is not performed. The statistical tests in Section 8.3 are not required for the yearly RATA.

* * * * *

12.4 Relative Accuracy Audit. Calculate the quarterly RAA using Equation 16–9.

$$RAA = \frac{\overline{PEMS} - \overline{RM}}{\overline{RM}} x\,100 \qquad \text{Eq. 16-9}$$

* * * * *

13.5 Relative Accuracy Audits. The average of the three portable analyzer or RM determinations must not differ from the simultaneous PEMS average value by more than 10 percent of the analyzer or RM for concentrations greater than 100 ppm or 20 percent for concentrations between 100 and 20 ppm, or the test is failed. For measurements at 20 ppm or less, this difference must not exceed 2 ppm for a pollutant PEMS and 1 percent absolute for a diluents PEMS.

* * * * *

■ 31. Amend appendix F to Part 60 as follows:

■ a. By revising Procedure 1, section 6.2.

■ b. By revising Procedure 2, paragraphs (3) and (4) of section 12.0.

■ c. By redesignating the second listing of section 6.2.6 as section 6.2.7 in Procedure 5.

Appendix F to Part 60—Quality Assurance Procedures

* * * * *

Procedure 1—Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determination

* * * * *

6.2 RAA Accuracy Calculation. Use the calculation procedure in the relevant performance specification to calculate the accuracy for the RAA. The RAA must be calculated in the units of the applicable emission standard.

* * * * *

Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources

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12.0 What calculations and data analysis must I perform for my PM CEMS?

* * * * *

(3) How do I calculate daily upscale and zero drift? You must calculate the upscale drift using Equation 2–2 and the zero drift using Equation 2–3:

$$UD = \frac{|R_{CEM} - R_U|}{FS} x\,100 \qquad \text{(Eq. 2-2)}$$

Where:

UD = The upscale drift of your PM CEMS, in percent,

R_{CEM} = Your PM CEMS response to the upscale check value, and

R_U = The upscale check value.

FS = Full-scale value.

$$ZD = \frac{|R_{CEM} - R_L|}{FS} x\,100 \qquad \text{(Eq. 2-3)}$$

Where:

ZD = The zero (low-level) drift of your PM CEMS, in percent,

R_{CEM} = Your PM CEMS response of the zero check value,

R_L = The zero check value.

(4) How do I calculate SVA accuracy? You must use Equation 2–4 to calculate the accuracy, in percent, for each of the three SVA tests or the daily sample volume check:

$$Accuracy = \frac{(V_R - V_M)}{V_R} x\,100 \qquad \text{(Eq. 2-4)}$$

Where:

V_M = Sample gas volume determined/ reported by your PM CEMS (e.g., dscm),

V_R = Sample gas volume measured by the independent calibrated reference device (e.g., dscm) for the SVA or the reference value for the daily sample volume check.

Note: Before calculating SVA accuracy, you must correct the sample gas volumes measured by your PM CEMS and the independent calibrated reference device to the same basis of temperature, pressure, and moisture content. You must document all data and calculations.

* * * * *

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

■ 32. The authority citation for part 61 continues to read as follows:

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

Subpart A—[Amended]

■ 33. Amend § 61.13 by revising paragraph (e)(1)(i) to read as follows:

§ 61.13 Emission tests and waiver of emission tests.

* * * * *

(e) * * *

(1) * * *

(i) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A–3 of part 60; Methods 6C, 7E, 9, and 10 of appendix A–4 of part 60; Method 18 and 19 of appendix A–6 of part 60; Methods 20, 22, and 25A of appendix A–7 of part 60; and Methods 303, 318, 320, and 321 of appendix A of part 63. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, *www.epa.gov/ttn/emc*, to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request, and the compliance authority may grant, a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and then report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

* * * * *

Subpart C—[Amended]

■ 34. Amend § 61.33 by revising paragraph (a) to read as follows:

§ 61.33 Stack sampling.

(a) Unless a waiver of emission testing is obtained under § 61.13, each owner or operator required to comply with § 61.32(a) shall test emissions from the source according to Method 104 of appendix B to this part or according to Method 29 of appendix A to part 60. Method 103 of appendix B to this part is approved by the Administrator as an alternative method for sources subject to § 61.32(a). The emission test shall be performed:

(1) By May 28, 2014 in the case of an existing source or a new source which has an initial startup date preceding February 27, 2014; or

(2) Within 90 days of startup in the case of a new source which did not have an initial startup date preceding February 27, 2014.

* * * * *

Subpart D—[Amended]

■ 35. Amend § 61.42 by revising paragraph (a) to read as follows:

§ 61.42 Emission standard.

(a) Emissions to the atmosphere from rocket-motor test sites shall not cause time-weighted atmospheric concentrations of beryllium to exceed 75 microgram minutes per cubic meter ($\mu g\text{-}min/m^3$)(4.68×10^{-9} pound minutes per cubic foot ($lb\text{-}min/ft^3$)) of air within the limits of 10 to 60 minutes, accumulated during any 2 consecutive weeks, in any area in which an adverse effect to public health could occur.

* * * * *

Subpart E—[Amended]

■ 36. Amend § 61.53 by revising paragraph (d)(2) to read as follows:

§ 61.53 Stack sampling.

* * * * *

(d) * * *

(2) Method 101A in appendix B or Method 29 in appendix A to part 60 shall be used to test emissions as follows:

(i) The test shall be performed by May 28, 2014 in the case of an existing source or a new source which has an initial startup date preceding February 27, 2014.

(ii) The test shall be performed within 90 days of startup in the case of a new source which did not have an initial startup date preceding February 27, 2014.

* * * * *

Subpart N—[Amended]

■ 37. Amend § 61.164 as follows:

■ a. By revising paragraph (d)(2)(i).

■ b. By revising paragraph (e)(1)(i).

■ c. By revising paragraph (e)(2) to read as follows:

§ 61.164 Test methods and procedures.

* * * * *

(d) * * *

(2) * * *

(i) Use Method 108 in appendix B to this part or Method 29 in appendix A to part 60 for determining the arsenic

emission rate, g/hr (lb/hr). The emission rate shall equal the arithmetic mean of the results of three 60-minute test runs.

* * * * *

(e) * * *

(1) * * *

(i) Use Method 108 in appendix B to this part or Method 29 in appendix A to part 60 to determine the concentration of arsenic in the gas streams entering and exiting the control device. Conduct three 60-minute test runs, each consisting of simultaneous testing of the inlet and outlet gas streams. The gas streams shall contain all the gas exhausted from the glass melting furnace.

* * * * *

(2) Calculate the percent emission reduction for each run as follows:

$$D = \frac{(C_b - C_a) \times 100}{C_b}$$

Where:

D = the percent emission reduction.

C_b = the arsenic concentration of the stack gas entering the control device, as measured by Method 108 or Method 29.

C_a = the arsenic concentration of the stack gas exiting the control device, as measured by Method 108 or Method 29.

* * * * *

■ 38. Amend appendix B to part 61 to read as follows:

■ a. By amending Method 101 by redesignating sections 16.0 and 17.0 as sections 17.0 and 18.0, respectively, and by adding a new section 16.0.

■ b. By amending Method 101A by redesignating sections 16.0 and 17.0 as sections 17.0 and 18.0, respectively, and by adding a new section 16.0.

■ c. By revising Method 102, section 8.1.1.1.

■ d. By amending Method 104 as follows:

■ i. By revising sections 4.1 and 11.5.3.

■ ii. By redesignating sections 16.0 and 17.0 as sections 17.0 and 18.0, respectively.

■ iii. By adding a new section 16.0.

■ e. By amending Method 108 by redesignating sections 16.0 and 17.0 as sections 17.0 and 18.0, respectively, and by adding a new section 16.0.

■ f. By amending Method 108A by redesignating sections 16.0 and 17.0 as sections 17.0 and 18.0 respectively, and by adding a new section 16.0.

Appendix B to Part 61—Test Methods

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Method 101—Determination of Particulate and Gaseous Mercury Emissions From Chlor-Alkali Plants (Air Streams)

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16.0 Alternative Procedures

16.1 Alternative Analyzer. Samples may also be analyzed by cold vapor atomic fluorescence spectrometry.

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Method 101A—Determination of Particulate and Gaseous Mercury Emissions From Sewage Sludge Incinerators

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16.0 Alternative Procedures

16.1 Alternative Analyzers.

16.1.1 Inductively coupled plasma-atomic emission spectrometry (ICP–AES) may be used as an alternative to atomic absorption analysis provided the following conditions are met:

16.1.1.1 Sample collection, sample preparation, and analytical preparation procedures are as defined in the method except as necessary for the ICP–AES application.

16.1.1.2 The quality control procedures are conducted as prescribed.

16.1.1.3 The limit of quantitation for the ICP–AES must be demonstrated and the sample concentrations reported should be no less than two times the limit of quantitation. The limit of quantitation is defined as ten times the standard deviation of the blank value. The standard deviation of the blank value is determined from the analysis of seven blanks. It has been reported that for mercury and those elements that form hydrides, a continuous-flow generator coupled to an ICP–AES offers detection limits comparable to cold vapor atomic absorption.

16.1.2 Samples may also be analyzed by cold vapor atomic fluorescence spectrometry.

* * * * *

Method 102—Determination of Particulate and Gaseous Mercury Emissions From Chlor-Alkali Plants (Hydrogen Streams)

* * * * *

8.1.1.1 Calibrate the meter box orifice. Use the techniques described in APTD–0576 (see Reference 9 in Section 17.0 of Method 5 of appendix A to part 60). Calibration of the orifice meter at flow conditions that simulate the conditions at the source is suggested. Calibration should either be done with hydrogen or with some other gas having a similar Reynolds Number so that there is similarity between the Reynolds Numbers during calibration and during sampling. Alternative mercury-free thermometers may be used if the thermometers are, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application.

* * * * *

Method 104—Determination of Beryllium Emissions From Stationary Sources

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4.1 Matrix Effects. Analysis for Be by flame atomic absorption spectrophotometry is sensitive to the chemical composition and to the physical properties (*e.g.*, viscosity, pH) of the sample. Aluminum and silicon, in particular, are known to interfere when present in appreciable quantities. The analytical procedure includes (optionally) the use of the Method of Standard Additions to check for these matrix effects, and sample analysis using the Method of Standard Additions if significant matrix effects are found to be present (see Reference 2 in Section 17.0).

* * * * *

11.5.3 Check for Matrix Effects (optional). Use the Method of Standard Additions (see Reference 2 in Section 17.0) to check at least one sample from each source for matrix effects on the Be results. If the results of the Method of Standard Additions procedure used on the single source sample do not agree to within 5 percent of the value obtained by the routine atomic absorption analysis, then reanalyze all samples from the source using the Method of Standard Additions procedure.

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16.0 Alternative Procedures

16.1 Inductively Coupled Plasma-Atomic Emission Spectrometry (ICP–AES) Analysis. ICP–AES may be used as an alternative to atomic absorption analysis provided the following conditions are met:

16.1.1 Sample collection, sample preparation, and analytical preparation procedures are as defined in the method except as necessary for the ICP–AES application.

16.1.2 Quality Assurance/Quality Control procedures, including audit material analysis, are conducted as prescribed in the method. The QA acceptance conditions must be met.

16.1.3 The limit of quantitation for the ICP–AES must be demonstrated and the sample concentrations reported should be no less than two times the limit of quantitation. The limit of quantitation is defined as ten times the standard deviation of the blank value. The standard deviation of the blank value is determined from the analysis of seven blanks. It has been reported that for mercury and those elements that form hydrides, a continuous-flow generator coupled to an ICP–AES offers detection limits comparable to cold vapor atomic absorption.

16.2 Inductively Coupled Plasma-Mass Spectrometry (ICP–MS) Analysis. ICP–MS may be used as an alternative to atomic absorption analysis.

16.3 Cold Vapor Atomic Fluorescence Spectrometry (CVAFS) Analysis. CVAFS may be used as an alternative to atomic absorption analysis.

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Method 108—Determination of Particulate and Gaseous Arsenic Emissions

* * * * *

16.0 Alternative Procedures

16.1 Inductively coupled plasma-atomic emission spectrometry (ICP–AES) Analysis. ICP–AES may be used as an alternative to atomic absorption analysis provided the following conditions are met:

16.1.1 Sample collection, sample preparation, and analytical preparation procedures are as defined in the method

except as necessary for the ICP–AES application.

16.1.2 Quality Assurance/Quality Control procedures, including audit material analysis, are conducted as prescribed in the method. The QA acceptance conditions must be met.

16.1.3 The limit of quantitation for the ICP–AES must be demonstrated and the sample concentrations reported should be no less than two times the limit of quantitation. The limit of quantitation is defined as ten times the standard deviation of the blank value. The standard deviation of the blank value is determined from the analysis of seven blanks. It has been reported that for mercury and those elements that form hydrides, a continuous-flow generator coupled to an ICP–AES offers detection limits comparable to cold vapor atomic absorption.

16.2 Inductively Coupled Plasma-Mass Spectrometry (ICP–MS) Analysis. ICP–MS may be used as an alternative to atomic absorption analysis.

16.3 Cold Vapor Atomic Fluorescence Spectrometry (CVAFS) Analysis. CVAFS may be used as an alternative to atomic absorption analysis.

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Method 108A—Determination of Arsenic Content in Ore Samples From Nonferrous Smelters

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16.0 Alternative Procedures

16.1 Alternative Analyzer. Inductively coupled plasma-atomic emission spectrometry (ICP–AES) may be used as an alternative to atomic absorption analysis provided the following conditions are met:

16.1.1 Sample collection, sample preparation, and analytical preparation procedures are as defined in the method except as necessary for the ICP–AES application.

16.1.2 Quality Assurance/Quality Control procedures, including audit material analysis, are conducted as prescribed in the method. The QA acceptance conditions must be met.

16.1.3 The limit of quantitation for the ICP–AES must be demonstrated and the sample concentrations reported should be no less than two times the limit of quantitation. The limit of quantitation is defined as ten times the standard deviation of the blank value. The standard deviation of the blank value is determined from the analysis of seven blanks. It has been reported that for mercury and those elements that form hydrides, a continuous-flow generator coupled to an ICP–AES offers detection limits comparable to cold vapor atomic absorption.

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

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

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

Subpart A—[Amended]

■ 40. Amend § 63.7 by revising paragraph (c)(2)(iii)(A) to read as follows:

§ 63.7 Performance testing requirements.

* * * * *

(c) * * *

(2) * * *

(iii) * * *

(A) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A–3 of part 60; Methods 6C, 7E, 9, and 10 of appendix A–4 of part 60; Methods 18 and 19 of appendix A–6 of part 60; Methods 20, 22, and 25A of appendix A–7 of part 60; and Methods 303, 318, 320, and 321 of appendix A of part 63. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, *www.epa.gov/ttn/emc*, to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request, and the compliance authority may grant, a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and then report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

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■ 41. Amend § 63.8 by adding a sentence to the end of paragraph (f)(6)(iii) to read as follows:

§ 63.8 Monitoring requirements.

* * * * *

(f) * * *

(6) * * *

(iii) * * * The Administrator will review the notification and may rescind permission to use an alternative and require the owner or operator to conduct a relative accuracy test of the CEMS as specified in section 8.4 of Performance Specification 2.

* * * * *

■ 42. Revise § 63.14 to read as follows:

§ 63.14 Incorporations by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the **Federal Register** under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the EPA must publish notice of change in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at the Air and Radiation Docket and Information Center, U.S. EPA, 401 M St. SW., Washington, DC, telephone number 202–566, and is available from the sources listed below. It is also available for inspection at the National Archives and Records Administration (NARA). For

information on the availability of this material at NARA, call 202–741–6030 or go to *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(b) The Association of Florida Phosphate Chemists, P.O. Box 1645, Bartow, Florida 33830.

(1) Book of Methods Used and Adopted By The Association of Florida Phosphate Chemists, Seventh Edition 1991:

(i) Section IX, Methods of Analysis for Phosphate Rock, No. 1 Preparation of Sample, IBR approved for §§ 63.606(c) and 63.626(c).

(ii) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus—P_2O_5 or $Ca_3(PO_4)_2$, Method A—Volumetric Method, IBR approved for §§ 63.606(c) and 63.626(c).

(iii) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P_2O_5 or $Ca_3(PO_4)_2$, Method B—Gravimetric Quimociac Method, IBR approved for §§ 63.606(c) and 63.626(c).

(iv) Section IX, Methods of Analysis For Phosphate Rock, No. 3 Phosphorus—P_2O_5 or $Ca_3(PO_4)_2$, Method C—Spectrophotometric Method, IBR approved for §§ 63.606(c) and 63.626(c).

(v) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus—P_2O_5, Method A—Volumetric Method, IBR approved for §§ 63.606(c) and 63.626(c) and (d).

(vi) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus—P_2O_5, Method B—Gravimetric Quimociac Method, IBR approved for §§ 63.606(c) and 63.626(c) and (d).

(vii) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus—P_2O_5, Method C—Spectrophotometric Method, IBR approved for §§ 63.606(c) and 63.626(c) and (d).

(2) [Reserved]

(c) Association of Official Analytical Chemists (AOAC) International, Customer Services, Suite 400, 2200 Wilson Boulevard, Arlington, Virginia 22201–3301, Telephone (703) 522–3032, Fax (703) 522–5468.

(1) AOAC Official Method 929.01 Sampling of Solid Fertilizers, Sixteenth edition, 1995, IBR approved for § 63.626(d).

(2) AOAC Official Method 929.02 Preparation of Fertilizer Sample, Sixteenth edition, 1995, IBR approved for § 63.626(d).

(3) AOAC Official Method 957.02 Phosphorus (Total) in Fertilizers, Preparation of Sample Solution, Sixteenth edition, 1995, IBR approved for § 63.626(d).

(4) AOAC Official Method 958.01 Phosphorus (Total) in Fertilizers, Spectrophotometric Molybdovanadophosphate Method, Sixteenth edition, 1995, IBR approved for § 63.626(d).

(5) AOAC Official Method 962.02 Phosphorus (Total) in Fertilizers, Gravimetric Quinolinium Molybdophosphate Method, Sixteenth edition, 1995, IBR approved for § 63.626(d).

(6) AOAC Official Method 969.02 Phosphorus (Total) in Fertilizers, Alkalimetric Quinolinium Molybdophosphate Method, Sixteenth edition, 1995, IBR approved for § 63.626(d).

(7) AOAC Official Method 978.01 Phosphorus (Total) in Fertilizers, Automated Method, Sixteenth edition, 1995, IBR approved for § 63.626(d).

(d) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005.

(1) API Publication 2517, Evaporative Loss from External Floating-Roof Tanks, Third Edition, February 1989, IBR approved for §§ 63.111 and 63.2406.

(2) API Publication 2518, Evaporative Loss from Fixed-roof Tanks, Second Edition, October 1991, IBR approved for § 63.150(g).

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

(e) American Society of Heating, Refrigerating, and Air-Conditioning Engineers at 1791 Tullie Circle, NE., Atlanta, GA 30329 *orders@ashrae.org.*

(1) American Society of Heating, Refrigerating, and Air Conditioning Engineers Method 52.1, "Gravimetric and Dust-Spot Procedures for Testing Air-Cleaning Devices Used in General Ventilation for Removing Particulate Matter, June 4, 1992," IBR approved for §§ 63.11173(e) and 63.11516(d).

(2) [Reserved]

(f) American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990, Telephone (800) 843–2763, *http://www.asme.org;* also available from HIS, Incorporated, 15 Inverness Way East, Englewood, CO 80112, Telephone (877) 413–5184, *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), 63.457(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), table 4 to subpart UUUU, 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), and 63.11945, table 5 to subpart DDDDD, table 4 to subpart JJJJJ, tables 4 and 5 of subpart UUUUU, and table 1 to subpart ZZZZZ.

(2) [Reserved]

(g) American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, Telephone (610) 832–9585, *http://www.astm.org;* also available from ProQuest, 789 East Eisenhower Parkway, Ann Arbor, MI 48106–1346, Telephone (734) 761–4700, *http://www.proquest.com.*

(1) 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.

(2) 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.

(3) ASTM Method D388–05, Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for §§ 63.7575, 63.10042, and 63.11237.

(4) ASTM Method D396–10, Standard Specification for Fuel Oils, including Appendix X1, approved October 1, 2010, IBR approved for § 63.10042.

(5) ASTM D396–10, Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for §§ 63.7575 and 63.11237.

(6) ASTM D523–89, Standard Test Method for Specular Gloss, IBR approved for § 63.782.

(7) ASTM D975–11b, Standard Specification for Diesel Fuel Oils, approved December 1, 2011, IBR approved for § 63.7575.

(8) ASTM D1193–77, Standard Specification for Reagent Water, IBR approved for appendix A to part 63: Method 306, Sections 7.1.1 and 7.4.2.

(9) ASTM D1193–91, Standard Specification for Reagent Water, IBR approved for appendix A to part 63: Method 306, Sections 7.1.1 and 7.4.2.

(10) ASTM D1331–89, Standard Test Methods for Surface and Interfacial Tension of Solutions of Surface Active Agents, IBR approved for appendix A to part 63: Method 306B, Sections 6.2, 11.1, and 12.2.2.

(11) ASTM D1475–90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for appendix A to subpart II.

(12) ASTM D1475–98 (Reapproved 2003), "Standard Test Method for Density of Liquid Coatings, Inks, and Related Products," IBR approved for §§ 63.3151(b), 63.3941(b) and (c), 63.3951(c), 63.4141(b) and (c), and 63.4551(c).

(13) ASTM Method D1835–05, Standard Specification for Liquefied Petroleum (LP) Gases, approved April 1, 2005, IBR approved for §§ 63.7575 and 63.11237.

(14) 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).

(15) ASTM D1946–77, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for § 63.11(b).

(16) ASTM D1946–90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for § 63.11(b).

(17) ASTM D2013/D2013M–09, Standard Practice for Preparing Coal Samples for Analysis, (Approved November 1, 2009), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(18) ASTM D2099–00, Standard Test Method for Dynamic Water Resistance of Shoe Upper Leather by the Maeser Water Penetration Tester, IBR approved for § 63.5350.

(19) ASTM D2216–05, Standard Test Methods for Laboratory Determination of Water (Moisture) Content of Soil and Rock by Mass, IBR approved for the definition of "Free organic liquids" in § 63.10692.

(20) ASTM D2234/D2234M–10, Standard Practice for Collection of a Gross Sample of Coal, approved January 1, 2010, IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ .

(21) ASTM D2369–93, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A to subpart II.

(22) ASTM D2369–95, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A to subpart II.

(23) ASTM D2382–76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for § 63.11(b).

(24) ASTM D2382–88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for § 63.11(b).

(25) ASTM D2697–86 (Reapproved 1998), Standard Test Method for Volume Nonvolatile Matter in Clear or Pigmented Coatings, IBR approved for §§ 63.3161(f), 63.3521(b), 63.3941(b), 63.4141(b), 63.4741(b), 63.4941(b), and 63.5160(c).

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

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

(28) ASTM D3173–03 (Reapproved 2008), Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, (Approved February 1, 2008), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(29) ASTM D3257–93, Standard Test Methods for Aromatics in Mineral Spirits by Gas Chromatography, IBR approved for § 63.786(b).

(30) 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).

(31) ASTM D3695–88, Standard Test Method for Volatile Alcohols in Water by Direct Aqueous-Injection Gas Chromatography, IBR approved for § 63.365(e).

(32) ASTM D3792–91, Standard Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A to subpart II.

(33) ASTM D3912–80, Standard Test Method for Chemical Resistance of Coatings Used in Light-Water Nuclear Power Plants, IBR approved for § 63.782.

(34) 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 D4017–81, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A to subpart II.

(36) ASTM D4017–90, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A to subpart II.

(37) ASTM D4017–96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A to subpart II.

(38) 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.

(39) ASTM D4082–89, Standard Test Method for Effects of Gamma Radiation on Coatings for Use in Light-Water Nuclear Power Plants, IBR approved for § 63.782.

(40) ASTM D4084–07, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), (Approved June 1, 2007), IBR approved for table 6 to subpart DDDDD.

(41) 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.

(42) ASTM D4208–02 (Reapproved 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.

(43) ASTM D4256–89, Standard Test Method for Determination of the Decontaminability of Coatings Used in Light-Water Nuclear Power Plants, IBR approved for § 63.782.

(44) ASTM D4256–89 (Reapproved 94), Standard Test Method for Determination of the Decontaminability of Coatings Used in Light-Water Nuclear Power Plants, IBR approved for § 63.782.

(45) ASTM D4606–03 (Reapproved 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.

(46) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for § 63.11(b).

(47) 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).

(48) ASTM D5066–91 (Reapproved 2001), Standard Test Method for Determination of the Transfer Efficiency Under Production Conditions for Spray Application of Automotive Paints-

Weight Basis, IBR approved for § 63.3161(g).

(49) ASTM D5087–02, Standard Test Method for Determining Amount of Volatile Organic Compound (VOC) Released from Solventborne Automotive Coatings and Available for Removal in a VOC Control Device (Abatement), IBR approved for § 63.3165(e) and appendix A to subpart IIII.

(50) ASTM D5192–09, Standard Practice for Collection of Coal Samples from Core, (Approved June 1, 2009), IBR approved for table 6 to subpart DDDDD.

(51) ASTM D5198–09, Standard Practice for Nitric Acid Digestion of Solid Waste, (Approved February 1, 2009), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(52) ASTM D5228–92, Standard Test Method for Determination of Butane Working Capacity of Activated Carbon, (Reapproved 2005), IBR approved for § 63.11092(b).

(53) ASTM D5291–02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, IBR approved for appendix A to subpart MMMM.

(54) ASTM D5790–95, Standard Test Method for Measurement of Purgeable Organic Compounds in Water by Capillary Column Gas Chromatography/Mass Spectrometry, IBR approved for Table 4 to subpart UUUU.

(55) 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.

(56) ASTM D5865–10a, Standard Test Method for Gross Calorific Value of Coal and Coke, (Approved May 1, 2010), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(57) ASTM D5954–98 (Reapproved 2006), Test Method for Mercury Sampling and Measurement in Natural Gas by Atomic Absorption Spectroscopy, (Approved December 1, 2006), IBR approved for table 6 to subpart DDDDD.

(58) ASTM D5965–02, Standard Test Methods for Specific Gravity of Coating Powders, IBR approved for §§ 63.3151(b) and 63.3951(c).

(59) ASTM D6053–00, Standard Test Method for Determination of Volatile Organic Compound (VOC) Content of Electrical Insulating Varnishes, IBR approved for appendix A to subpart MMMM.

(60) ASTM D6093–97 (Reapproved 2003), Standard Test Method for Percent Volume Nonvolatile Matter in Clear or Pigmented Coatings Using a Helium Gas Pycnometer, IBR approved for §§ 63.3161, 63.3521, 63.3941, 63.4141, 63.4741(b), 63.4941(b), and 63.5160(c).

(61) ASTM D6266–00a, Test Method for Determining the Amount of Volatile Organic Compound (VOC) Released from Waterborne Automotive Coatings and Available for Removal in a VOC Control Device (Abatement), IBR approved for § 63.3165(e).

(62) ASTM D6323–98 (Reapproved 2003), Standard Guide for Laboratory Subsampling of Media Related to Waste Management Activities, (Approved August 10, 2003), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(63) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for §§ 63.457(b) and 63.1349, table 4 to subpart DDDD, table 4 to subpart ZZZZ, and table 8 to subpart HHHHHHH.

(64) ASTM D6348–03 (Reapproved 2010), Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, including Annexes A1 through A8, (Approved October 1, 2010), IBR approved for tables 1, 2, and 5 to subpart UUUUU and appendix B to subpart UUUUU.

(65) ASTM D6350–98 (Reapproved 2003), Standard Test Method for Mercury Sampling and Analysis in Natural Gas by Atomic Fluorescence Spectroscopy, (Approved May 10, 2003), IBR approved for table 6 to subpart DDDDD.

(66) 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.

(67) ASTM D6420–99, Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, IBR approved for §§ 63.5799, 63.5850, and Table 4 of Subpart UUUU.

(68) 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 §§ 63.457(b), 63.485(g), 60.485a(g), 63.772(a), 63.772(e), 63.1282(a) and (d), 63.2351(b), and 63.2354(b), and table 8 to subpart HHHHHHH.

(69) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 63.9307(c).

(70) 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, table 5 to subpart DDDDDD, table 4 to subpart JJJJJJ, and §§ 63.772(e) and (h)) and 63.1282(d) and (g).

(71) ASTM D6721–01 (Reapproved 2006), Standard Test Method for Determination of Chlorine in Coal by Oxidative Hydrolysis Microcoulometry, (Approved April 1, 2006), IBR approved for table 6 to subpart DDDDD.

(72) ASTM D6722–01 (Reapproved 2006), Standard Test Method for Total Mercury in Coal and Coal Combustion Residues by the Direct Combustion Analysis, (Approved April 1, 2006), IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ.

(73) 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.

(74) 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 §§ 63.11646(a), 63.11647(a) and (d), tables 1, 2, 5, 11, 12t, and 13 to subpart DDDDD, table 4 to subpart JJJJJJ, table 5 to subpart UUUUU, and appendix A to subpart UUUUU.

(75) 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.

(76) ASTM D7430–11ae1, Standard Practice for Mechanical Sampling of Coal, (Approved October 1, 2011), IBR approved for table 6 to subpart DDDDD.

(77) ASTM E145–94 (Reapproved 2001), Standard Specification for Gravity-Convection and Forced-Ventilation Ovens, IBR approved for appendix A to subpart PPPP.

(78) ASTM E180–93, Standard Practice for Determining the Precision of

ASTM Methods for Analysis and Testing of Industrial Chemicals, IBR approved for § 63.786(b).

(79) ASTM E260–91, General Practice for Packed Column Gas Chromatography, IBR approved for §§ 63.750(b) and 63.786(b).

(80) ASTM E260–96, General Practice for Packed Column Gas Chromatography, IBR approved for §§ 63.750(b) and 63.786(b).

(81) ASTM E515–95 (Reapproved 2000), Standard Test Method for Leaks Using Bubble Emission Techniques, IBR approved for § 63.425(i).

(82) ASTM E711–87 (Reapproved 2004), Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, (Approved August 28, 1987), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(83) ASTM E776–87 (Reapproved 2009), Standard Test Method for Forms of Chlorine in Refuse-Derived Fuel, (Approved July 1, 2009), IBR approved for table 6 to subpart DDDDD.

(84) ASTM E871–82 (Reapproved 2006), Standard Test Method for Moisture Analysis of Particulate Wood Fuels, (Approved November 1, 2006), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(h) Bay Area Air Quality Management District (BAAQMD), 939 Ellis Street, San Francisco, California 94109, *http://www.arb.ca.gov/DRDB/BA/CURHTML/ST/st30.pdf.*

(1) "BAAQMD Source Test Procedure ST–30—Static Pressure Integrity Test, Underground Storage Tanks," adopted November 30, 1983, and amended December 21, 1994, IBR approved for § 63.11120(a).

(2) [Reserved]

(i) British Standards Institute, 389 Chiswick High Road, London W4 4AL, United Kingdom.

(1) BS EN 1593:1999, Non-destructive Testing: Leak Testing—Bubble Emission Techniques, IBR approved for § 63.425(i).

(2) [Reserved]

(j) California Air Resources Board (CARB), Engineering and Certification Branch, 1001 I Street, P.O. Box 2815, Sacramento, CA 95812–2815, Telephone (916) 327–0900, *http://www.arb.ca.gov/vapor/vapor.htm.*

(1) California Air Resources Board Vapor Recovery Test Procedure TP–201.1—"Volumetric Efficiency for Phase I Vapor Recovery Systems," adopted April 12, 1996, and amended February 1, 2001 and October 8, 2003, IBR approved for § 63.11120(b).

(2) California Air Resources Board Vapor Recovery Test Procedure TP–201.1E—"Leak Rate and Cracking Pressure of Pressure/Vacuum Vent Valves," adopted October 8, 2003, IBR approved for § 63.11120(a).

(3) California Air Resources Board Vapor Recovery Test Procedure TP–201.3—"Determination of 2-Inch WC Static Pressure Performance of Vapor Recovery Systems of Dispensing Facilities," adopted April 12, 1996 and amended March 17, 1999, IBR approved for § 63.11120(a).

(k) Environmental Protection Agency. Air and Radiation Docket and Information Center, 1200 Pennsylvania Avenue NW., Washington, DC 20460, telephone number (202) 566–1745.

(1) *California Regulatory Requirements Applicable to the Air Toxics Program,* November 16, 2010, IBR approved for § 63.99(a).

(2) New Jersey's *Toxic Catastrophe Prevention Act Program,* (July 20, 1998), IBR approved for § 63.99(a).

(3) Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management, Accidental Release Prevention Regulation, sections 1 through 5 and sections 7 through 14, effective January 11, 1999, IBR approved for § 63.99(a).

(4) State of Delaware Regulations Governing the Control of Air Pollution (October 2000), IBR approved for § 63.99(a).

(5) Massachusetts Department of Environmental Protection regulations at 310 CMR 7.26(10)–(16), Air Pollution Control, effective as of September 5, 2008, corrected March 6, 2009, and 310 CMR 70.00, Environmental Results Program Certification, effective as of December 28, 2007. IBR approved for § 63.99(a).

(6)(i) New Hampshire Regulations Applicable to Hazardous Air Pollutants, March, 2003. IBR approved for § 63.99(a).

(ii) New Hampshire Regulations Applicable to Hazardous Air Pollutants, September 2006. IBR approved for § 63.99(a).

(7) Maine Department of Environmental Protection regulations at Chapter 125, Perchloroethylene Dry Cleaner Regulation, effective as of June 2, 1991, last amended on June 24, 2009. IBR approved for § 63.99(a).

(8) California South Coast Air Quality Management District's "Spray Equipment Transfer Efficiency Test Procedure for Equipment User, May 24, 1989," IBR approved for §§ 63.11173(e) and 63.11516(d).

(9) California South Coast Air Quality Management District's "Guidelines for Demonstrating Equivalency with District Approved Transfer Efficient Spray Guns, September 26, 2002," Revision 0, IBR approved for §§ 63.11173(e) and 63.11516(d).

(10) Rhode Island Department of Environmental Management regulations at Air Pollution Control Regulation No. 36, Control of Emissions from Organic Solvent Cleaning, effective April 8, 1996, last amended October 9, 2008, IBR approved for § 63.99(a).

(11) Rhode Island Air Pollution Control, General Definitions Regulation, effective July 19, 2007, last amended October 9, 2008. IBR approved for § 63.99(a).

(12) Alaska Statute 42.45.045. Renewable energy grant fund and recommendation program, available at *http://www.legis.state.ak.us/basis/folio.asp,* IBR approved for § 63.6675.

(l) U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW., Washington, DC 20460, (202) 272–0167, *http://www.epa.gov.*

(1) EPA–453/R–01–005, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants—Background Information for Proposed Standards, Final Report, January 2001, IBR approved for § 63.7491(g).

(2) EPA–454/R–98–015, Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997, IBR approved for §§ 63.548(e), 63.7525(j), and 63.11224(f).

(3) SW–846–3020A, Acid Digestion of Aqueous Samples And Extracts For Total Metals For Analysis By GFAA Spectroscopy, Revision 1, July 1992, 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 and table 5 to subpart JJJJJJ.

(4) SW–846–3050B, Acid Digestion of Sediments, Sludges, and Soils, Revision 2, December 1996, 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 and table 5 to subpart JJJJJJ.

(5) SW–846–7470A, Mercury In Liquid Waste (Manual Cold-Vapor 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 and table 5 to subpart JJJJJJ.

(6) SW–846–7471B, Mercury In Solid Or Semisolid Waste (Manual Cold-Vapor Technique), Revision 2, 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 and table 5 to subpart JJJJJJ.

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

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

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

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

(11) 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.

(12) 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.

(13) 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.

(14) 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.

(15) 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.

(16) 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.

(17) 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.

(18) SW–846–9250, Chloride (Colorimetric, Automated Ferricyanide AAI), 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.

(19) 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.

(20) 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.

(m) International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*.

(1) ISO 6978–1:2003(E), Natural Gas—Determination of Mercury—Part 1: Sampling of Mercury by Chemisorption on Iodine, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD.

(2) ISO 6978–2:2003(E), Natural gas—Determination of Mercury—Part 2: Sampling of Mercury by Amalgamation on Gold/Platinum Alloy, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD.

(n) National Council of the Paper Industry for Air and Stream Improvement, Inc. (NCASI), P.O. Box 133318, Research Triangle Park, NC 27709–3318 or at *http://www.ncasi.org*.

(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.

(2) NCASI Method CI/WP–98.01, Chilled Impinger Method For Use At Wood Products Mills to Measure Formaldehyde, Methanol, and Phenol, 1998, Methods Manual, IBR approved for table 4 to subpart DDDD.

(3) NCASI Method DI/HAPS–99.01, Selected HAPs In Condensates by GC/FID, Issued February 2000, IBR approved for § 63.459(b).

(4) NCASI Method IM/CAN/WP–99.02, Impinger/Canister Source Sampling Method for Selected HAPs and Other Compounds at Wood Products Facilities, January 2004, Methods Manual, IBR approved for table 4 to subpart DDDD.

(5) NCASI Method ISS/FP A105.01, Impinger Source Sampling Method for Selected Aldehydes, Ketones, and Polar Compounds, December 2005, Methods Manual, IBR approved for table 4 to subpart DDDD.

(o) National Technical Information Service (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 605–6000 or (800) 553–6847; or for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512–1800.

(1) Handbook 44, Specificiations, Tolerances, and Other Technical Requirements for Weighing and Measuring Devices 1998, IBR approved for § 63.1303(e).

(2) "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW–846, Third Edition. (A suffix of "A" in the method number indicates revision one (the method has been revised once). A suffix of "B" in the method number indicates revision two (the method has been revised twice).

(i) Method 0023A, "Sampling Method for Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofuran Emissions from Stationary Sources," dated December 1996, IBR approved for § 63.1208(b).

(ii) Method 9071B, "n-Hexane Extractable Material (HEM) for Sludge, Sediment, and Solid Samples," dated April 1998, IBR approved for § 63.7824(e).

(iii) Method 9095A, "Paint Filter Liquids Test," dated December 1996, IBR approved for §§ 63.7700(b) and 63.7765.

(iv) Method 9095B, "Paint Filter Liquids Test," (revision 2), dated November 2004, IBR approved for the definition of "Free organic liquids" in §§ 63.10692, 63.10885(a), and the definition of "Free liquids" in § 63.10906.

(v) SW–846 74741B, Revision 2, "Mercury in Solid or Semisolid Waste (Manual Cold-Vapor Technique)," February 2007, IBR approved for § 63.11647(f).

(3) National Institute of Occupational Safety and Health (NIOSH) test method compendium, "NIOSH Manual of Analytical Methods," NIOSH publication no. 94–113, Fourth Edition, August 15, 1994.

(i) NIOSH Method 2010, "Amines, Aliphatic," Issue 2, August 15, 1994, IBR approved for § 63.7732(g).

(ii) [Reserved]

(p) North American Electric Reliability Corporation, 1325 G Street, NW., Suite 600, Washington, DC 20005–3801, *http://www.nerc.com, http://www.nerc.com/files/EOP0002-3_1.pdf.*

(1) North American Electric Reliability Corporation Reliability Standard EOP–002–3, Capacity and Energy Emergencies, adopted August 5, 2010, IBR approved for § 63.6640(f).

(2)[Reserved]

(q) 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]

(r) Texas Commission on Environmental Quality (TCEQ) Library, Post Office Box 13087, Austin, Texas 78711–3087, telephone number (512) 239–0028, *http://www.tceq.state.tx.us/assets/public/implementation/air/sip/sipdocs/2002-12-HGB/02046sipapp_ado.pdf.*

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

(2) [Reserved]

Subpart G—[Amended]

■ 43. Amend § 63.144 by adding paragraphs (b)(5)(i)(G) and (H) to read as follows:

§ 63.144 Process wastewater provisions—test methods and procedures for determining applicability and Group 1/Group 2 determinations (determining which wastewater streams require control).

* * * * *

(b) * * *

(5) * * *

(i) * * *

(G) *Method 8260B.* Use procedures specified in Method 8260B in the SW–846 Compendium of Methods.

(H) *Method 316.* Use Method 316 to determine formaldehyde concentration.

* * * * *

Subpart N—[Amended]

■ 44. Amend § 63.344 by adding paragraph (c)(5) to read as follows:

§ 63.344 Performance test requirements and test methods.

* * * * *

(c) * * *

(5) The South Coast Air Quality Management District (SCAQMD) Method 205.1 (which is available by contacting the South Coast AQMD, 21865 Copley Dr, Diamond Bar, CA 91765) may be used to determine the total chromium concentration from hard and decorative chromium electroplating tanks and chromium anodizing tanks.

* * * * *

Subpart O—[Amended]

■ 45. Amend § 63.364 by revising paragraph (e) to read as follows:

§ 63.364 Monitoring requirements.

* * * * *

(e) Measure and record once per hour the ethylene oxide concentration at the outlet to the atmosphere after any control device according to the procedures specified in § 63.365(c)(1). The owner or operator shall compute and record a 24-hour average daily. The owner or operator will install, calibrate, operate, and maintain a monitor consistent with the requirements of performance specification (PS) 8 or 9 in 40 CFR part 60, appendix B, to measure ethylene oxide. The daily calibration requirements of section 7.2 of PS–9 or Section 13.1 of PS–8 are required only on days when ethylene oxide emissions are vented to the control device.

* * * * *

■ 46. Amend § 63.365 by revising the introductory text of paragraph (b) to read as follows:

§ 63.365 Test methods and procedures.

* * * * *

(b) *Efficiency at the sterilization chamber vent.* California Air Resources Board (CARB) Method 431 or the following procedures shall be used to determine the efficiency of all types of control devices used to comply with § 63.362(c), sterilization chamber vent standard.

* * * * *

Subpart Y—[Amended]

■ 47. Amend § 63.565 by revising paragraphs (d)(5), (8), and (10) and (g) to read as follows:

§ 63.565 Test methods and procedures.

* * * * *

(d) * * *

(5) *Recovery devices.* The average VOC concentration in the vent upstream and downstream of the control device shall be determined using Method 25A or 25B of appendix A–7 to part 60 of this chapter for recovery devices. The average VOC concentration shall correspond to the volume measurement by taking into account the sampling system response time.

* * * * *

(8) Where Method 25, 25A, or 25B is used to measure the percent reduction in VOC, the percent reduction across the combustion or recovery device shall be calculated as follows:

$$R = \frac{E_i - E_o}{E_i}(100\%)$$

Where:

R = control efficiency of control device, percent.

E_i = mass flow rate of VOC at the inlet to the combustion or recovery device as calculated under paragraph (c)(7) of this section, kg/hr.

E_o = mass flow rate of VOC at the outlet of the combustion or recovery device, as calculated under paragraph (c)(7) of this section, kg/hr.

* * * * *

(10) Use of methods other than Method 25, 25A, or 25B shall be validated pursuant to Method 301 of appendix A to part 63 of this chapter.

* * * * *

(g) *Baseline outlet VOC concentration.* The procedures in this paragraph shall be used to determine the outlet VOC concentration required in § 63.563(b)(4), (6), (7), and (8) for combustion devices except flare, carbon adsorbers, condenser/refrigeration units, and absorbers, respectively, and to monitor the VOC concentration as required in § 63.564(e), (g), (h), and (i). The owner or operator shall use the procedures outlined in Method 25A or 25B. For the baseline VOC concentration, the arithmetic average of the outlet VOC concentration from three test runs from paragraph (d) of this section shall be calculated for the control device. The VOC concentration shall be measured at least every 15 minutes. Compliance testing of VOC CEMS shall be performed using PS 8.

* * * * *

Subpart GG—[Amended]

■ 48. Amend § 63.750 by revising paragraph (o) to read as follows:

§ 63.750 Test methods and procedures.

* * * * *

(o) *Inorganic HAP emissions—dry particulate filter certification requirements.* Dry particulate filters used to comply with § 63.745(g)(2) or § 63.746(b)(4) must be certified by the filter manufacturer or distributor, paint/depainting booth supplier, and/or the facility owner or operator using method 319 in appendix A of this part, to meet or exceed the efficiency data points found in Tables 1 and 2, or 3 and 4 of § 63.745 for existing or new sources respectively.

Subpart GGG—[Amended]

■ 49. Amend § 63.1251 by revising the definition of "Process vent" to read as follows:

§ 63.1251 Definitions.

* * * * *

Process vent means a vent from a unit operation or vents from multiple unit operations within a process that are manifolded together into a common header, through which a HAP-containing gas stream is, or has the potential to be, released to the atmosphere. Examples of process vents include, but are not limited to, vents on condensers used for product recovery, bottom receivers, surge control vessels, reactors, filters, centrifuges, and process tanks. Emission streams that are undiluted and uncontrolled containing less than 50 ppmv HAP, as determined through process knowledge that no HAP are present in the emission stream or using an engineering assessment as discussed in § 63.1257(d)(2)(ii); test data using Method 18 of 40 CFR part 60, appendix A–6; Method 320 of 40 CFR part 63; or any other test method that has been validated according to the procedures in Method 301 of appendix A of this part, are not considered process vents. Process vents do not include vents on storage tanks regulated under § 63.1253, vents on wastewater emission sources regulated under § 63.1256, or pieces of equipment regulated under § 63.1255.

* * * * *

Subpart RRR—[Amended]

■ 50. Amend § 63.1511 by revising paragraph (c)(9) as to read follows:

§ 63.1511 Performance test/compliance demonstration general requirements.

* * * * *

(c) * * *

(9) Method 26A for the concentration of HCl. Where a lime-injected fabric filter is used as the control device to comply with the 90 percent reduction standard, the owner or operator must measure the fabric filter inlet concentration of HCl at a point before lime is introduced to the system. Method 26 may be used in place of Method 26A where it can be demonstrated that there are no water droplets in the emission stream. This can be demonstrated by showing that the vapor pressure of water in the emission stream that you are testing is less than the equilibrium vapor pressure of water at the emission stream temperature, and by certifying that the emission stream is not controlled by a wet scrubber.

* * * * *

Subpart CCCC—[Amended]

■ 51. Revise Table 2 to subpart CCCC to read as follows:

As stated in § 63.2161, if you demonstrate compliance by monitoring brew ethanol, you must comply with the requirements for performance tests in the following table:

TABLE 2 TO SUBPART CCCC OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS

[Brew Ethanol Monitoring Only]

For each fed-batch fermenter for which compliance is determined by monitoring brew ethanol concentration and calculating VOC concentration in the fermenter exhaust according to the procedures in § 63.2161, you must . . .	Using . . .	According to the following requirements . . .
1. Measure VOC as propane	Method 25A*, or an alternative validated by EPA Method 301 * and approved by the Administrator.	You must measure the VOC concentration in the fermenter exhaust at any point prior to the dilution of the exhaust stream.

* EPA Test Methods found in Appendix A of 40 CFR part 60.

Subpart UUUU—[Amended]

■ 52. Revise Table 4 to subpart UUUU to read as follows:

As required in §§ 63.5530(b) and 63.5535(a), (b), (g)(1), and (h)(1), you must conduct performance tests, other initial compliance demonstrations, and CEMS performance evaluations and establish operating limits according to the requirements in the following table:

TABLE 4 TO SUBPART UUUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS

For . . .	at . . .	you must . . .	using . . .	according to the following requirements . . .
1. the sum of all process vents.	a. each existing or new affected source.	i. select sampling port's location and the number of traverse points;	EPA Method 1 or 1A in appendix A to 40 CFR § 63.7(d)(1)(i);	sampling sites must be located at the inlet and outlet to each control device;
		ii. determine velocity and volumetric flow rate;	EPA Method 2, 2A, 2C, 2D, 2F, or 2G in appendices A–1 and A–2 to part 60 of this chapter;	you may use EPA Method 2A, 2C, 2D, 2F, or 2G as an alternative to using EPA Method 2, as appropriate;

TABLE 4 TO SUBPART UUUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For	at	you must	using	according to the following requirements . . .
		ii. conduct gas analysis; and,	(1) EPA Method 3, 3A, or 3B in appendix A–2 to part 60 of this chapter; or,	you may use EPA Method 3A or 3B as an alternative to using EPA Method 3; or,
			(2) ASME PTC 19.10–1981—Part 10; and,	you may use ASME PTC 19.10–1981—Part 10 (available for purchase from Three Park Avenue, New York, NY 10016–5990) as an alternative to using EPA Method 3B.
		iv. measure moisture content of the stack gas.	EPA Method 4 in appendix A–3 to part 60 of this chapter.	
2. the sum of all viscose process vents.	a. each existing or new viscose process source.	i. measure total sulfide emissions.	(1) EPA Method 15 in appendix A–5 to part 60 of this chapter; or	(a) you must conduct testing of emissions at the inlet and outlet of each control device;
				(b) you must conduct testing of emissions from continuous viscose process vents and combinations of batch and continuous viscose process vents at normal operating conditions, as specified in §§ 63.7(e)(1) and 63.5535;
				(c) you must conduct testing of emissions from batch viscose process vents as specified in § 63.490(c), except that the emission reductions required for process vents under this subpart supersede the emission reductions required for process vents under subpart U of this part; and
				(d) you must collect CPMS data during the period of the initial compliance demonstration and determine the CPMS operating limit during the period of the initial compliance demonstration; or
			(2) carbon disulfide and/or hydrogen sulfide CEMS, as applicable;	(a) you must measure emissions at the inlet and outlet of each control device using CEMS;
				(b) you must install, operate, and maintain the CEMS according to the applicable performance specification (PS–7, PS–8, PS–9, or PS–15) of 40 CFR part 60, appendix B; and
				(c) you must collect CEMS emissions data at the inlet and outlet of each control device during the period of the initial compliance demonstration and determine the CEMS operating limit during the period of the initial compliance demonstration.
3. the sum of all solvent coating process vents.	a. each existing or new cellophane operation.	i. measure toluene emissions.	(1) EPA Method 18 in appendix A–6 to part 60 of this chapter, or Method 320 in appendix A to part 60, or	(a) you must conduct testing of emissions at the inlet and outlet of each control device;
				(b) you may use EPA Method 18 or 320 to determine the control efficiency of any control device for organic compounds; for a combustion device, you must use only HAP that are present in the inlet to the control device to characterize the percent reduction across the combustion device;
				(c) you must conduct testing of emissions from continuous solvent coating process vents and combinations of batch and continuous solvent coating process vents at normal operating conditions, as specified in §§ 63.7(e)(1) and 63.5535;

TABLE 4 TO SUBPART UUUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For . . .	at	you must . .	using	according to the following requirements . . .
				(d) you must conduct testing of emissions from batch solvent coating process vents as specified in § 63.490(c), except that the emission reductions required for process vents under this subpart supersede the emission reductions required for process vents under subpart U of this part; and
				(e) you must collect CPMS data during the period of the initial compliance demonstration and determine the CPMS operating limit during the initial compliance demonstration; or
			(2) ASTM D6420–99	(a) you must conduct testing of emissions at the inlet and outlet of each control device;
				(b) you may use ASTM D6420–99 (available for purchase from at least one of the following addresses: 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959; or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106) as an alternative to EPA Method 18 only where: the target compound(s) are those listed in Section 1.1 of ASTM D6420–99; and the target concentration is between 150 parts per billion by volume (ppbv) and 100 ppmv; for target compound(s) not listed in Section 1.1 of ASTM D6420–99, but potentially detected by mass spectrometry, the additional system continuing calibration check after each run, as detailed in Section 10.5.3 of the ASTM method, must be followed, met, documented, and submitted with the data report even if there is no moisture condenser used or the compound is not considered water soluble; and for target compound(s) not listed in Section 1.1 of ASTM D6420–99 and not amenable to detection by mass spectrometry, ASTM D6420–99 does not apply;
				(c) you must conduct testing of emissions from continuous solvent coating process vents and combinations of batch and continuous solvent coating process vents at normal operating conditions, as specified in §§ 63.7(e)(1) and 63.5535;
				(d) you must conduct testing of emissions from batch solvent coating process vents as specified in § 63.490(c), except that the emission reductions required for process vents under this subpart supersede the emission reductions required for process vents under subpart U of this part; and,
				(e) you must collect CPMS data during the period of the initial compliance demonstration and determine the CPMS operating limit during the period of the initial compliance demonstration.
4. the sum of all cellulose ether process vents.	a each existing or new cellulose ether operation.	measure total organic HAP emissions.	(1) EPA Method 18 in appendix A–6 to part 60 of this chapter or Method 320 in appendix A to part 63, or	(a) you must conduct testing of emissions at the inlet and outlet of each control device;
				(b) you may use EPA Method 18 or 320 to determine the control efficiency of any control device for organic compounds; for a combustion device, you must use only HAP that are present in the inlet to the control device to characterize the percent reduction across the combustion device;

TABLE 4 TO SUBPART UUUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For . . .	at .	you must	using	according to the following requirements . . .
				(c) you must conduct testing of emissions from continuous cellulose ether process vents and combinations of batch and continuous cellulose ether process vents at normal operating conditions, as specified in §§ 63.7(e)(1) and 63.5535; (d) you must conduct testing of emissions from batch cellulose ether process vents as specified in § 63.490(c), except that the emission reductions required for process vents under this subpart supersede the emission reductions required for process vents under subpart U of this part; and (e) you must collect CPMS data during the period of the initial performance test and determine the CPMS operating limit during the period of the initial performance test;
			(2) ASTM D6420–99	(a) you must conduct testing of emissions at the inlet and outlet of each control device; (b) you may use ASTM D6420–99 (available for purchase from at least one of the following addresses: 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959; or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106) as an alternative to EPA Method 18 only where: the target compound(s) are those listed in Section 1.1 of ASTM D6420–99; and the target concentration is between 150 ppbv and 100 ppmv; for target compound(s) not listed in Section 1.1 of ASTM D6420–99, but potentially detected by mass spectrometry, the additional system continuing calibration check after each run, as detailed in Section 10.5.3 of the ASTM method, must be followed, met, documented, and submitted with the data report even if there is no moisture condenser used or the compound is not considered water soluble; and for target compound(s) not listed in Section 1.1 of ASTM D6420–99 and not amenable to detection by mass spectrometry, ASTM D6420–99 does not apply; target concentration is between 150 ppbv and 100 ppmv for target compound(s). (c) you must conduct testing of emissions from continuous cellulose ether process vents and combinations of batch and continuous cellulose ether process vents at normal operating conditions, as specified in §§ 63.7(e)(1) and 63.5535; (d) you must conduct testing of emissions from batch cellulose ether process vents as specified in § 63.490(c), except that the emission reductions required for process vents under this subpart supersede the emission reductions required for process vents under subpart U of this part; and (e) you must collect CPMS data during the period of the initial performance test and determine the CPMS operating limit during the period of the initial performance test.
			(3) EPA Method 25 in appendix A–7 to part 60 of this chapter; or	(a) you must conduct testing of emissions at the inlet and outlet of each control device;

TABLE 4 TO SUBPART UUUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For . . .	at . . .	you must:	using	according to the following requirements . . .
				(b) you may use EPA Method 25 to determine the control efficiency of combustion devices for organic compounds; you may not use EPA Method 25 to determine the control efficiency of noncombustion control devices; (c) you must conduct testing of emissions from continuous cellulose ether process vents and combinations of batch and continuous cellulose ether process vents at normal operating conditions, as specified in §§ 63.7(e)(1) and 63.5535; (d) you must conduct testing of emissions from batch cellulose ether process vents as specified in § 63.490(c), except that the emission reductions required for process vents under this subpart supersede the emission reductions required for process vents under subpart U of this part; and (e) you must collect CPMS data during the period of the initial performance test and determine the CPMS operating limit during the period of the initial performance test; or
			(4) EPA Method 25A in appendix A–7 to part 60 of this chapter	(a) you must conduct testing of emissions at the inlet and outlet of each control device; (b) you may use EPA Method 25A if: an exhaust gas volatile organic matter concentration of 50 ppmv or less is required in order to comply with the emission limit; the volatile organic matter concentration at the inlet to the control device and the required level of control are such as to result in exhaust volatile organic matter concentrations of 50 ppmv or less; or because of the high control efficiency of the control device, the anticipated volatile organic matter concentration at the control device exhaust is 50 ppmv or less, regardless of the inlet concentration; (c) you must conduct testing of emissions from continuous cellulose ether process vents and combinations of batch and continuous cellulose ether process vents at normal operating conditions, as specified in §§ 63.7(e)(1) and 63.5535; (d) you must conduct testing of emissions from batch cellulose ether process vents as specified in § 63.490(c), except that the emission reductions required for process vents under this subpart supersede the emission reductions required for process vents under subpart U of this part; and, (e) you must collect CPMS data during the period of the initial performance test and determine the CPMS operating limit during the period of the initial performance test.
5. each toluene storage vessel.	a. each existing or new cellophane operation.	measure toluene emissions.	(1) EPA Method 18 in appendix A–6 to part 60 of this chapter or Method 320 in appendix A to part 63; or	(a) if venting to a control device to reduce emissions, you must conduct testing of emissions at the inlet and outlet of each control device;

TABLE 4 TO SUBPART UUUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For	ar	you must	using	according to the following requirements . . .
				(b) you may use EPA Method 18 or 320 to determine the control efficiency of any control device for organic compounds; for a combustion device, you must use only HAP that are present in the inlet to the control device to characterize the percent reduction across the combustion device; (c) you must conduct testing of emissions from continuous storage vessel vents and combinations of batch and continuous storage vessel vents at normal operating conditions, as specified in §§ 63.7(e)(1) and 63.5535 for continuous process vents; (d) you must conduct testing of emissions from batch storage vessel vents as specified in § 63.490(c) for batch process vents, except that the emission reductions required for process vents under this subpart supersede the emission reductions required for process vents under subpart U of this part; and, (e) you must collect CPMS data during the period of the initial compliance demonstration and determine the CPMS operating limit during the period of the initial compliance demonstration; or
			(2) ASTM D6420–99 ..	(a) if venting to a control device to reduce emissions, you must conduct testing of emissions at the inlet and outlet of each control device; (b) you may use ASTM D6420–99 (available for purchase from at least one of the following addresses: 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959; or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106) as an alternative to EPA Method 18 only where: the target compound(s) are those listed in Section 1.1 of ASTM D6420–99, and the target concentration is between 150 ppbv and 100 ppmv; for target compound(s) not listed in Section 1.1 of ASTM D6420–99, but potentially detected by mass spectrometry, the additional system continuing calibration check after each run, as detailed in Section 10.5.3 of the ASTM method, must be followed, met, documented, and submitted with the data report even if there is no moisture condenser used or the compound is not considered water soluble; and for target compound(s) not listed in Section 1.1 of ASTM D6420–99 and not amenable to detection by mass spectrometry, ASTM D6420–99 does not apply; (c) you must conduct testing of emissions from continuous storage vessel vents and combinations of batch and continuous storage vessel vents at normal operating conditions, as specified in §§ 63.7(e)(1) and 63.5535 for continuous process vents; (d) you must conduct testing of emissions from batch storage vessel vents as specified in § 63.490(c) for batch process vents, except that the emission reductions required for process vents under this subpart supersede the emission reductions required for process vents under subpart U of this part; and,

TABLE 4 TO SUBPART UUUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For . . .	at . . .	you must . . .	using . . .	according to the following requirements . . .
				(e) you must collect CPMS data during the period of the initial compliance demonstration and determine the CPMS operating limit during the period of the initial compliance demonstration.
6. the sum of all process vents controlled using a flare.	a. each existing or new affected source.	i. measure visible emissions.	(1) EPA Method 22 in appendix A–7 to part 60 of this chapter.	(a) you must conduct the flare visible emissions test according to § 63.11(b).
7. equipment leaks	a. each existing or new cellulose ether operation.	i. measure leak rate ...	(1) applicable equipment leak test methods in § 63.180; or	(a) you must follow all requirements for the applicable equipment leak test methods in § 63.180; or
			(2) applicable equipment leak test methods in § 63.1023	(a) you must follow all requirements for the applicable equipment leak test methods in § 63.1023.
8. all sources of wastewater emissions.	a. each existing or new cellulose ether operation.	i. measure wastewater HAP emissions.	(1) applicable wastewater test methods and procedures in §§ 63.144 and 63.145; or	(a) You must follow all requirements for the applicable wastewater test methods and procedures in §§ 63.144 and 63.145; or
			(2) applicable wastewater test methods and procedures in §§ 63.144 and 63.145, using ASTM D5790–95 as an alternative to EPA Method 624 in appendix A to part 163 of this chapter.	(a) you must follow all requirements for the applicable waste water test methods and procedures in §§ 63.144 and 63.145, except that you may use ASTM D5790–95 (available for purchase from at least one of the following addresses: 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959; or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106) as an alternative to EPA Method 624, under the condition that this ASTM method be used with the sampling procedures of EPA Method 25D or an equivalent method.
9. any emission point	a. each existing or new affected source using a CEMS to demonstrate compliance.	i. conduct a CEMS performance evaluation.	(1) applicable requirements in § 63.8 and applicable performance specification (PS–7, PS–8, PS–9, or PS–15) in appendix B to part 60 of this chapter.	(a) you must conduct the CEMS performance evaluation during the period of the initial compliance demonstration according to the applicable requirements in § 63.8 and the applicable performance specification (PS–7, PS–8, PS–9, or PS–15) of 40 CFR part 60, appendix B; (b) you must install, operate, and maintain the CEMS according to the applicable performance specification (PS–7, PS–8, PS–9, or PS–15) of 40 CFR part 60, appendix B; and (c) you must collect CEMS emissions data at the inlet and outlet of each control device during the period of the initial compliance demonstration and determine the CEMS operating limit during the period of the initial compliance demonstration.

Subpart ZZZZ—[Amended]

■ 53. Revise Table 4 to subpart ZZZZ to read as follows:

As stated in §§ 63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

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. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and	.....	(a) For CO and O_2 measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A–1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A–4.
		ii 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–2, or ASTM Method D6522–00 (Reapproved 2005)[a c] (heated probe not necessary).	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device.	(1) ASTM D6522–00 (Reapproved 2005)[a b c] (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A–4.	(c) The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE.	a. reduce formaldehyde emissions.	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and	.....	(a) For formaldehyde, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.
		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–2, or ASTM Method D6522–00 (Reapproved 2005)[a] (heated probe not necessary).	(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–3, or 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.

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 . . .
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formalde-hyde 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–7.	(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/location of traverse points at the exhaust of the stationary RICE; and	.....	(a) For formaldehyde, CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.
		i. 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–2, or ASTM Method D6522–00 (Reapproved 2005) [a] (heated probe not necessary).	(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 station-ary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A–3, or 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 station-ary 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.

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 . . .
		v. measure CO at the exhaust of the station-ary RICE.	(1) Method 10 of 40 CFR part 60, appendix A–4, 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] You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b] You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

■ 54. Amend appendix A to part 63 to read as follows:

■ a. By revising Method 306, sections 2.2.1 and 6.1.4, and the Note to section 8.0.

■ b. By revising Method 306A, section 8.2.

■ c. By revising Method 308, section 10.1.3.

■ d. By amending Method 315 as follows:

■ i. By revising section 6.1.1.

■ ii. By redesignating section 8.11 as section 8.1.

■ iii. By revising newly designated section 8.1.

■ iv. By revising section 10.5.

■ e. By revising Method 316, section 10.5.

■ f. By revising Method 321, the definition for the term "Df" in section 9.3.1.

Appendix A to Part 63—Test Methods Pollutant Measurement Methods From Various Waste Media

* * * * *

Method 306—Determination of Chromium Emissions From Decorative and Hard Chromium Electroplating and Chromium Anodizing Operations—Isokinetic Method

* * * * *

2.2.1 Total chromium samples with high chromium concentrations (≥35 μg/L) may be analyzed using inductively coupled plasma emission spectrometry (ICP) at 267.72 nm. Note: The ICP analysis is applicable for this method only when the solution analyzed has a Cr concentration greater than or equal to 35 μg/L or five times the method detection limit as determined according to appendix B in 40 CFR part 136. Similarly, inductively coupled plasma-mass spectroscopy (ICP–MS) may be used for total chromium analysis provided the procedures for ICP–MS analysis described in Method 6020 or 6020A (EPA Office of Solid Waste, publication SW–846) are followed.

* * * * *

6.1.4 Operating and maintenance procedures for the sampling train are described in APTD–0576 of Method 5. Users should read the APTD–0576 document and adopt the outlined procedures. Alternative mercury-free thermometers may be used if the thermometers are, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application.

* * * * *

8.0 Sample Collection, Preservation, Holding Times, Storage, and Transport

Note: Prior to sample collection, consideration should be given to the type of analysis (Cr^{+6} or total Cr) that will be performed. Which analysis option(s) will be performed will determine which sample recovery and storage procedures will be required to process the sample.

* * * * *

Method 306A—Determination of Chromium Emissions From Decorative and Hard Chromium Electroplating and Chromium Anodizing Operations

* * * * *

8.2 Sample Recovery. After the train has been transferred to the sample recovery area, disconnect the tubing that connects the jar/impingers. The tester shall select either the total Cr or Cr^{+6} sample recovery option. Samples to be analyzed for both total Cr and Cr^{+6} shall be recovered using the Cr^{+6} sample option (Section 8.2.2). Note: Collect a reagent blank sample for each of the total Cr or the Cr^{+6} analytical options. If both analyses (Cr and Cr^{+6}) are to be conducted on the samples, collect separate reagent blanks for each analysis. Also, since particulate matter is not usually present at chromium electroplating and/or chromium anodizing operations, it is not necessary to filter the Cr^{+6} samples unless there is observed sediment in the collected solutions. If it is necessary to filter the Cr^{+6} solutions, please refer to Method 0061, Determination of Hexavalent Chromium Emissions from Stationary Sources, Section 7.4, Sample Preparation in SW–846 (see Reference 1).

* * * * *

Method 308—Procedure for Determination of Methanol Emission From Stationary Sources

* * * * *

10.1.3 Temperature Sensors. Calibrate against mercury-in-glass thermometers. An alternative mercury-free thermometer may be used if the thermometer is, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application.

* * * * *

Method 315—Determination of Particulate and Methylene Chloride Extractable Matter (MCEM) From Selected Sources at Primary Aluminum Production Facilities

* * * * *

6.1.1 Sampling train. A schematic of the sampling train used in this method is shown in Figure 5–1, Method 5, 40 CFR part 60, appendix A–3. Complete construction details are given in APTD–0581 (Reference 2 in section 17.0 of this method); commercial models of this train are also available. For changes from APTD–0581 and for allowable modifications of the train shown in Figure 5–1, Method 5, 40 CFR part 60, appendix A–3, see the following subsections. Note: The operating and maintenance procedures for the sampling train are described in APTD–0576 (Reference 3 in section 17.0 of this method). Since correct usage is important in obtaining valid results, all users should read APTD–0576 and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. Alternative mercury-free thermometers may be used if the thermometers are, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application. The use of grease for sealing sampling train components is not recommended because many greases are soluble in methylene chloride. The sampling train consists of the following components:

* * * * *

8.1 Pretest preparation. It is suggested that sampling equipment be maintained according to the procedures described in APTD–0576. Alternative mercury-free thermometers may be used if the thermometers are at a minimum equivalent in terms of performance or suitably effective for the specific temperature measurement application.

* * * * *

10.5 Temperature sensors. Use the procedure in Section 10.3 of Method 2, 40 CFR part 60, appendix A–1 to calibrate in-stack temperature sensors. Dial thermometers, such as are used for the DGM and condenser outlet, shall be calibrated against mercury-in-glass thermometers. An alternative mercury-free thermometer may be used if the thermometer is, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application.

* * * * *

Method 316—Sampling and Analysis for Formaldehyde Emissions From Stationary Sources in the Mineral Wool and Wool Fiberglass Industries

* * * * *

10.5 Temperature gauges: Use the procedure in Section 4.3 of EPA Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers. An alternative mercury-free thermometer may be used if the thermometer is, at a minimum, equivalent in terms of performance or suitably effective for the specific temperature measurement application.

* * * * *

Test Method 321—Measurement of Gaseous Hydrogen Chloride Emissions at Portland Cement Kilns by Fourier Transform Infrared (FTIR) Spectroscopy

* * * * *

9.3.1 * * *

DF = Dilution Factor (Total flow/Spike flow). Total flow = spike flow plus effluent flow.

* * * * *

[FR Doc. 2014–02704 Filed 2–26–14; 8:45 am]

BILLING CODE 6560–50–P

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 the establishment of a safety zone and therefore it 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, 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. Chapters 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add § 165.T09–1012 to read as follows:

§ 165.T09–1012 Safety Zone; Vessel Launch; Menominee River; Marinette, WI.

(a) *Location.* All waters of the Menominee River in the vicinity of Marinette Marine Corporation, between the Bridge Street Bridge located in position 45°06′12″ N, 087°37′34″ W and a line crossing the river perpendicularly passing through position 45°05′57″ N, 087°36′43″ W, in the vicinity of the Ansul Company (NAD 83).

(b) *Effective and Enforcement Period.* This zone will be effective and enforced from 12:45 p.m. until 3:15 p.m. on December 18, 2013.

(c) *Regulations.* (1) In accordance with the general regulations in § 165.23 of this part, entry into, transiting, or anchoring within the safety zone is prohibited unless authorized by the Captain of the Port, Lake Michigan or his designated on-scene representative.

(2) The safety zone is closed to all vessel traffic, except as may be permitted by the Captain of the Port, Lake Michigan or his designated on-scene representative.

(3) The "on-scene representative" of the Captain of the Port, Lake Michigan, is any Coast Guard commissioned, warrant or petty officer who has been designated by the Captain of the Port, Lake Michigan, to act on his behalf.

(4) Vessel operators desiring to enter or operate within the safety zone shall contact the Captain of the Port, Lake Michigan, or his on-scene representative to obtain permission to do so. The Captain of the Port, Lake Michigan, or his on-scene representative may be contacted via VHF Channel 16. Vessel operators given permission to enter or operate in the safety zone must comply with all directions given to them by the Captain of the Port, Lake Michigan, or his on-scene representative.

Dated: December 9, 2013.

M.W. Sibley,

Captain, U.S. Coast Guard, Captain of the Port, Lake Michigan.

[FR Doc. 2013–30173 Filed 12–18–13; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2007–0011; FRL–9904–06–OAR]

RIN 2060–AS03

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: The Environmental Protection Agency (EPA) is taking direct final action to amend the Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007. This direct final rule amends the definition of "delayed coking unit" by removing process piping and associated equipment (pumps, valves, and connectors) from the definition. This final rule also removes a redundant definition of "delayed coking unit" from the rule text.

DATES: This rule is effective on March 19, 2014 without further notice, unless the EPA receives adverse comment by February 3, 2014. If the EPA receives adverse comment, we will publish a timely withdrawal in the **Federal Register** informing the public that some or all of the amendments in the final rule will not take effect.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID Number EPA–HQ–OAR–2007–0011, by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Attention Docket ID Number EPA–HQ–OAR–2007–0011.
- *Fax:* (202) 566–9744. Attention Docket ID Number EPA–HQ–OAR–2007–0011.
- *Mail:* U.S. Postal Service, send comments to: EPA Docket Center, EPA West (Air Docket), Attention Docket ID Number EPA–HQ–OAR–2007–0011, U.S. Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460. Please include a total of two copies.
- *Hand Delivery:* U.S. Environmental Protection Agency, EPA West (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC 20004. Attention Docket ID Number EPA–HQ–OAR–2007–0011. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions. Direct your comments to Docket ID Number EPA–HQ–OAR–2007–0011. The 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 the 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 the 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, the 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 the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at: *http://www.epa.gov/dockets*.

We request that you also send a separate copy of each comment to the contact person listed below (see **FOR FURTHER INFORMATION CONTACT**).

FOR FURTHER INFORMATION CONTACT: Ms. Brenda Shine, Sector Policies and Programs Division (E143–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–3608; fax number: (919) 541–0246; and email address: *shine.brenda@epa.gov*. For information about the applicability of the New Source Performance Standards (NSPS) to a particular entity, contact Maria Malave, Office of Enforcement and Compliance Assurance (OECA), U.S. Environmental Protection Agency, telephone number: (202) 564–7027; fax number: (202) 564–0050; and email address: *malave.maria@epa.gov*.

SUPPLEMENTARY INFORMATION:

Organization of This Document. The information in this preamble is organized as follows:

I. Why is the EPA using a direct final rule?

The EPA is publishing this direct final rule without a prior proposed rule because we view this as a noncontroversial action and anticipate no adverse comment. However, in the "Proposed Rules" section of today's **Federal Register**, we are publishing a separate document that will serve as the proposed rule to the Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007 (40 CFR part 60 subpart Ja), if adverse comments are received on this direct final rule. If EPA receives adverse comment on all or a distinct portion of this rule, we will publish a timely withdrawal in the **Federal Register** informing the public that some of this rule or this entire direct final rule will not take effect. The rule provisions that are not withdrawn will become effective on the date set out above, notwithstanding adverse comment on any other provision, unless we determine that it would not be appropriate to promulgate those provisions due to their being affected by the provision for which we receive adverse comments. We would address all public comments in any subsequent final rule based on the proposed rule. We will not institute a second comment period on this action. Any parties interested in commenting must do so at this time. For further information about commenting on this rule, see the **ADDRESSES** section of this document.

II. Does this direct final rule apply to me?

Categories and entities potentially regulated by this final rule include:

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

[1] North American Industry Classification System

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this direct final rule. To determine whether your facility would be regulated by this direct final rule, you should examine the applicability criteria in 40 CFR 60.100a. If you have any questions regarding the applicability of this direct final rule to a particular entity, contact the persons listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

III. What should I consider as I prepare my comments for the EPA?

Submitting CBI. Do not submit information containing CBI to the EPA through *http://www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI for inclusion in the public docket. If you submit a CD–ROM or disk that does not contain CBI, mark the outside of the disk or CD–ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2. Send or deliver information identified as CBI

only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, and Attention Docket ID Number EPA–HQ–OAR–2007–0011.

IV. What are the amendments made by this direct final rule?

Presently, "delayed coking unit" is defined as follows:

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; process piping and associated equipment such as pumps, valves and connectors; and the coke drum blowdown recovery compressor system.

40 CFR 60.101a. This direct final rule amends the definition of "delayed coking unit" by removing the phrase "process piping and associated equipment such as pumps, valves and connectors." Emissions from process piping and associated equipment (pumps, valves and connectors) are already covered under 40 CFR part 60, subparts GGG or GGGa; the controls required under this rule (40 CFR part 60, subpart Ja) do not address the emissions from such equipment. Rather, this rule addresses emissions from the delayed coking unit's process vent.

Although we included process piping and associated equipment in the definition of "delayed coking unit" because it is necessary to operate the delayed coking unit, the inclusion of this equipment within the definition results in very minor changes, such as adding a few valves and connectors for a new sample point or pressure gauge, to be considered a "modification" of the delayed coking unit. This is because, under the definition above, these additional valves would increase emissions from the delayed coking unit even though the increase would not occur at emissions points regulated under this rule. *See* 40 CFR 60.14. This was an inadvertent result as the EPA did not intend for such small changes to process piping and associated equipment (such as pumps, valves and connectors, which, as noted above, are regulated elsewhere), to constitute a modification of the delayed coking unit under 40 CFR part 60, subpart Ja. As a result, this modification would require immediate compliance with the coke drum vent control requirements in 40 CFR 60.103a(i). Thus, we are removing this phrase from the definition.

This direct final rule also removes a redundant definition of "delayed coking unit" from 40 CFR 60.101a. When 40 CFR part 60, subpart Ja, was amended on September 12, 2012 (77 FR 56422), we added new definitions that preceded the old definition of "delayed coking unit" alphabetically, and we amended the then-existing definition of "delayed coking unit." However, the old definition of "delayed coking unit" was not removed from the CFR when these other changes were made. Therefore, this direct final rule removes the old definition of "delayed coking unit," as it is no longer accurate and may be confusing to stakeholders.

Comments on this direct final rule are to be limited to issues directly associated with the amended definition of "delayed coking unit."

V. Statutory and Executive Order Reviews

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

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

B. Paperwork Reduction Act

This action does not impose any new information collection burden because it does not change the information collection requirements. However, OMB has previously approved the information collection requirements contained in the existing rule (40 CFR part 60, subpart Ja) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.*, and has assigned OMB control number 2060–0602. The OMB control numbers for the EPA's regulations are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

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

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

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. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives "which minimize any significant economic impact of the rule on small entities." 5 U.S.C. 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule.

This rule will not impose any requirements on small entities, and no small entities are expected to incur annualized costs as a result of the amendments. The amendments may reduce burden for small entities with delayed coking units. We have determined that the amendments will not result in any "significant" adverse economic impact for small entities. This amendment does not create any new requirements or burdens, and no costs are associated with this amendment. We have, therefore, concluded that this final rule will relieve regulatory burden for all affected small entities.

D. Unfunded Mandates Reform Act

This rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. The costs of the final amendments would not increase costs associated with the final rule. Thus, this rule is not subject to the requirements of sections 202 or 205 of the UMRA.

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

E. Executive Order 13132: Federalism

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

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

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

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

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

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

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 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 to use available and applicable VCS.

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

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of Congress and to the Comptroller General of the United States. The EPA will submit a report containing these final rules and other required information to the United States Senate, the United States House of Representatives and the Comptroller General of the United States prior to publication of the final rules in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This direct final rule will be effective on March 19, 2014.

List of Subjects in 40 CFR Part 60

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

Dated: December 4, 2013.

Gina McCarthy,

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 Ja—[AMENDED]

■ 2. Section 60.101a is amended by:

■ a. Removing the first definition of "delayed coking unit" that occurs out of alphabetical order between the terms "contact material" and "corrective action" and

■ b. Revising the second definition of "delayed coking unit." The revisions read as follows:

§ 60.101a Definitions.

* * * * *

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; and the coke drum blowdown recovery compressor system.

* * * * *

[FR Doc. 2013–29731 Filed 12–18–13; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL REGISTER

Vol. 78 Monday,
No. 184 September 23, 2013

Part III

Environmental Protection Agency

40 CFR Part 60
Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505, FRL–9844–4]

RIN 2060–AR75

Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final Amendments.

SUMMARY: This action finalizes the amendments to new source performance standards for the oil and natural gas sector. The Administrator received petitions for reconsideration of certain aspects of the August 12, 2012, final standards. These amendments are a result of reconsideration of certain issues raised by petitioners related to implementation of storage vessel provisions. The final amendments provide clarity of notification and compliance dates, ensure control of all storage vessel affected facilities and update key definitions. This action also corrects technical errors that were inadvertently included in the final standards.

DATES: This final rule is effective on September 23, 2013.

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. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning 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*.

SUPPLEMENTARY INFORMATION:

Organization of This Document. The information presented in this preamble is organized as follows:

I. Preamble Acronyms and Abbreviations

Several acronyms and terms 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
AVO Auditory, Visual and Olfactory
BOE Barrels of Oil Equivalent
bbl Barrel
bpd Barrels Per Day
BID Background Information Document
BSER Best System of Emissions Reduction
CAA Clean Air Act
CFR Code of Federal Regulations
CPMS Continuous Parametric Monitoring Systems
EIA Energy Information Administration
EPA Environmental Protection Agency
GOR Gas to Oil Ratio
HAP Hazardous Air Pollutant
HPDI HPDI, LLC
Mcf Thousand Cubic Feet
NTTAA National Technology Transfer and Advancement Act of 1995
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NSPS New Source Performance Standards
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PRA Paperwork Reduction Act
PTE Potential to Emit
RFA Regulatory Flexibility Act
SISNOSE Significant Economic Impact on a Substantial Number of Small Entities
tpy Tons per Year
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. General Information

A. Executive Summary

1. Purpose of This Regulatory Action

The purpose of this action is to finalize amendments to the 40 CFR part 60, subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and

Distribution final rule promulgated under section 111(b) of the Clean Air Act (CAA), which was published on August 16, 2012 [77 FR 49490]. The amendments being finalized were proposed on April 12, 2012 [78 FR 22126]. Specifically, this final rule action amends aspects of the 2012 new source performance standards (2012 NSPS) to address select issues raised by different stakeholders through several administrative petitions for reconsideration of the 2012 NSPS. The select issues being reconsidered and addressed by this action are related primarily to implementation of the storage vessel provisions.

2. Summary of Major Amendments to the NSPS

This rule finalizes a number of aspects of the proposal but, after consideration of public comments received, it also makes certain changes, as described in this section.

a. Initial Notification and Compliance Dates

For Group 1 storage vessels (*i.e.*, those the construction, reconstruction or modification of which began after August 23, 2011, and on or before April 12, 2013),[1] the final amendments require that owners/operators estimate emissions from the storage vessels to determine affected facility no later than October 15, 2013, and a notification be submitted with the facilities' annual report due by January 15, 2014, to inform regulatory agencies of the existence and location of the Group 1 storage vessel affected facilities. The final amendments retain the requirement that all Group 1 storage vessel affected facilities comply with the emission standards but, in a change from proposal, extend the compliance deadline to April 15, 2015. Since all Group 1 affected facilities are required to meet the emission standards, the final amendments do not require Group 1 storage vessel affected facilities to track emission increase events, as we had proposed.

For Group 2 storage vessel affected facilities (*i.e.*, those the construction, reconstruction or modification of which began after April 12, 2013), the final amendments extend the compliance date to April 15, 2014 (or 60 days after startup, whichever is later), for implementing the emission standards, as proposed.

In response to comments regarding the confusion about when the affected facility status for Group 1 storage vessels should be determined, we have also made clarifying changes to § 60.5365(e) in the final amendments that clearly specify October 15, 2013, as the deadline for calculating potential volatile organic compound (VOC) emissions from Group 1 storage vessels for determining the affected facility status.

b. Group 1 and Group 2 Storage Vessel Emission Standards Applicability

We have amended § 60.5395 to more clearly specify that the requirements of the NSPS apply to Group 1 and Group 2 storage vessel *affected* facilities (*i.e.*, those with potential to emit (PTE) 6 or more tpy of VOC, as determined by the methods and dates specified in this final rule). We amended this language in response to several comments expressing confusion about whether the requirements applied to all Group 1 storage vessels or just those with VOC emissions of 6 tpy or greater (*i.e.*, affected facilities).

c. Group 1 Storage Vessel Affected Facility Emission Standards and Compliance Dates

A key feature of this action is that the final amendments require control of all storage vessel affected facilities constructed since the August 23, 2011, proposal date of the 2012 NSPS. This decision, as summarized in this section and discussed fully in sections IV.A and V.C of this preamble, was based on new information we received that indicates that the projected control device supply appears to be greater than we originally estimated.

In the preamble to the proposed amendments, based on the information then available to the EPA, we developed an estimate of the supply of the type of combustors likely to be used by owners and operators to comply with the control requirements and concluded that control supply would not catch up with its demand under this rule until 2016. To avoid delaying control until such time, we proposed that Group 1 affected facilities notify the EPA of their presence and location by October 15, 2013, but need not comply with the 95 percent reduction requirement unless they experience an emission increase event. However, new information we received since proposal indicates that the combustor suppliers have the manufacturing capacity to meet the demand posed both by this regulation and a variety of state and local regulations that require the installation of control devices. Therefore, in the final amendments, we are not changing the requirement of the 2012 NSPS that Group 1 storage vessel affected facilities comply with the emission standard requirements. However, we have extended the current compliance deadline. For the reasons discussed in detail in section IV.A, these final amendments require that Group 2 affected facilities comply with the emission standards by April 15, 2014, as we proposed, and that Group 1 affected facilities comply by April 15, 2015.

d. Alternative 4-tpy Uncontrolled Actual VOC Emission Rate

To help alleviate the control supply shortage believed to exist at the time, we had proposed that affected facilities meet the 95% reduction requirement or an uncontrolled actual VOC emission rate of less than 4 tpy, which would allow control devices to be removed from storage vessel affected sources below that emission rate and relocated to those that have just come on line and have PTE of 6 tpy VOC or more. As mentioned above, new information we received since proposal indicate that the combustor suppliers have the manufacturing capacity to meet the demand posed by this regulation, which in turn would suggest that a supply buffer may no longer be necessary. However, for the reasons provided in section V.C of this preamble, we are finalizing the amendment to the storage vessel emission standards as proposed due to questionable cost effectiveness, the secondary environmental impact and the energy impacts from the continued operation of the combustion control device at an inlet stream concentration of less than about 4 tpy. We were aware but had not highlighted these concerns in the proposed amendment because the perceived supply problem alone necessitated proposing the amendment. The resolution of the supply issue, however, shifts our focus back to these concerns. As explained in more detail in section V.C of this preamble, in light of the questionable cost effectiveness of additional control, the secondary environmental impact and the energy impacts we conclude that the best system of emissions reduction (BSER) for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained uncontrolled emission rates fall below 4 tpy. We are therefore finalizing the amendment as proposed. Under the final amendments, an owner or operator may comply with the uncontrolled actual VOC emission rate instead of the 95 percent control requirement where it can be demonstrated that, based on records of monthly determinations of actual

[1] The 2012 NSPS proposal was published on August 23, 2011, and the proposed rule for this action was published on April 12, 2013.

emission rate for the 12 consecutive months immediately preceding the demonstration, that the storage vessel affected facility uncontrolled actual VOC emissions for each month during that 12-month period have been below 4 tpy. The final amendments require that the owner or operator re-evaluate the uncontrolled actual VOC emissions on a monthly basis. If the results of the monthly determination show that the uncontrolled actual VOC emission rate is 4 tpy or more, the owner or operator would have 30 days to meet the 95 percent control requirement. We discuss this further in section V.C of this preamble.

e. Definition of Storage Vessel Affected Facility

We have finalized the proposed amendments to the definition of "storage vessel affected facility" in the final rule (see § 60.5365(e)) to (1) include the 6 tpy VOC emission threshold and to clarify that a source can take into account any legally and practically enforceable emission limit under federal, state, local or tribal authority when determining the VOC emission rate for purposes of this threshold; (2) clarify that a storage vessel affected facility whose VOC PTE decreases to less than 6 tpy would remain an affected facility; and (3) to clarify that PTE does not include any vapor recovered and routed to a process.

f. Streamlined Compliance Monitoring Provisions

We received several comments regarding the streamlined compliance monitoring provisions; our review of the comments did not result in significant changes since proposal. These compliance monitoring provisions include inspections of covers, closed-vent systems and control devices, performed at least monthly. We believe that these measures are sufficient to ensure that storage vessel affected facilities that have installed controls meet the 95 percent VOC reduction standard. Although the more stringent compliance monitoring provisions in the 2012 NSPS may provide better assurance of compliance, there are significant issues regarding their implementation, which have been raised in several administrative reconsideration petitions. We continue to evaluate the reconsideration issues related to compliance monitoring and intend to complete our reconsideration by the end of 2014.

3. Cost and Benefits

Owners and operators of storage vessel affected facilities are expected to install and operate the same or similar air pollution control technologies under these final amendments as would have been necessary to meet the previously finalized standards for the oil and natural gas sector under the 2012 NSPS. We project that these amendments will not result in a significant change in costs and or benefits compared to the 2012 NSPS. The final amendments continue to require that all storage vessel affected facilities comply with the emission standards. Although the final amendments may not achieve the same level of emission reductions as the 2012 NSPS, it was necessary to revise the standards due to the limitations of the 2012 rule. The revisions provided in the final amendments were needed for the reasons explained in this preamble, and we believe the rule provides significant benefits. We anticipate that, if there are any changes in costs for these units, 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.

B. Does this reconsideration notice apply to me?

Categories and entities potentially affected by today's notice include:

TABLE 1—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. How do I obtain a copy of this document and other related information?

In addition to being available in the docket, electronic copies of these proposed rules will be available on the Worldwide Web through the Technology Transfer Network (TTN). Following signature, a copy of each proposed rule 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 November 22, 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 the EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was

impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

III. Summary of Final Amendments

The final amendments include revisions to certain reconsidered aspects of the existing 2012 NSPS which primarily affect the implementation of the regulation of VOC emissions from storage vessels. A summary of the final amendments resulting from our reconsideration are provided in the following paragraphs.

A. Initial Notification and Compliance Dates

For Group 1 storage vessel affected facilities, we have amended the 2012 NSPS to require that a notification be submitted with the initial annual report, to inform regulatory agencies of the existence and location of the vessels. In addition, we have amended the 2012 NSPS to require that all Group 1 storage vessel affected facilities comply with the emission standards no later than April 15, 2015, and that all Group 2 storage vessel affected facilities comply no later than April 15, 2014, (or 60 days after startup, whichever is later).

The final amendments also make clarifying changes to § 60.5395 that clearly specify October 15, 2013, as the deadline for calculating potential VOC emissions from Group 1 storage vessels to determine affected facility status.

B. Group 1 and Group 2 Storage Vessel Emission Standards Applicability

We have amended § 60.5395 to clearly state that the emission standards apply to Group 1 and Group 2 storage vessel affected facilities (as opposed to all storage vessels).

C. Group 1 Storage Vessel Affected Facility Control Requirements

The final amendments retain the requirement in the 2012 NSPS that all storage vessel affected facilities meet the emission standards. However, the final amendments require that owners and operators of Group 1 storage vessel affected facilities comply with the emission standards by April 15, 2015, and that Group 2 storage vessel affected facilities comply by April 15, 2014.

D. Alterative 4-tpy Uncontrolled Actual VOC Emission Rate

We have amended the storage vessel standards to include a sustained uncontrolled actual VOC emission rate of less than 4 tpy. Specifically, an owner or operator may comply with the uncontrolled actual VOC emission rate instead of the 95 percent control requirement where it can be demonstrated that, based on records of monthly emission estimates for the 12 months immediately preceding the demonstration, that the storage vessel affected facility uncontrolled actual VOC emissions estimated each of those months were below 4 tpy. The owner or operator would be required to re-evaluate the uncontrolled actual VOC emissions on a monthly basis. If the results of the monthly determination show that the uncontrolled actual VOC emission rate is 4 tpy or more, the owner or operator would have 30 days to meet the 95 percent control requirement, unless the increase was associated with the fracturing or refracturing of a well feeding the storage vessel affected facility. In that case, 95 percent control would be required as soon as liquids are routed from the fractured or refractured well to the storage vessel. We discuss this further in section V.C of this preamble.

E. Definition of Storage Vessel

The final amendments revise the definition of "storage vessel" to clarify that it refers only to vessels containing crude oil, condensate, intermediate hydrocarbon liquids or produced water.

F. Definition of Storage Vessel Affected Facility

The final amendments revise the definition of "storage vessel affected facility" (see § 60.5365(e)) to (1) include the 6 tpy VOC emission limit and to clarify that a source can take into account any legally and practically enforceable emission limit under federal, state, local or tribal authority when determining the VOC emission rate for purposes of this threshold; (2) clarify that a storage vessel affected facility whose VOC PTE decreases to less than 6 tpy would remain an affected facility; (3) clarify that "other mechanisms" (or non-federally enforceable mechanisms) must be legally and practically enforceable under federal, state, local or tribal authority; and (4) clarify that vapor from a storage vessel that is recovered and routed to a process is not to be counted in the PTE for purposes of determining affected facility status.

We also added language at § 60.5395(f) to address storage vessel affected facilities that are removed from service. Owners and operators are required to include a notification in their next annual report that the storage vessel has been taken out of service. If a storage vessel's return to service is associated with fracturing or refracturing of a well feeding the storage vessel, the storage vessel is subject to control requirements immediately upon returning to service. If, however, the storage vessel's return to service is not associated with well fracturing or refracturing, the PTE of the storage vessel must be determined within 30 days. If the PTE is 4 tpy or greater, then the storage vessel affected facility must comply with control requirements within 60 days of returning to service.

G. Streamlined Compliance Monitoring Provisions

For storage vessels that install controls to meet the 95 percent VOC reduction standard, we have amended the 2012 NSPS to adopt the streamlined compliance monitoring provisions as proposed without significant changes. These compliance monitoring provisions include inspections performed at least monthly of covers, closed-vent systems and control devices. As mentioned above, we continue to evaluate the reconsideration issues raised concerning the compliance monitoring provisions in the 2012 NSPS and intend to complete our reconsideration by the end of 2014.

H. Combustion Control Device Manufacturer Test Protocol

We have finalized amendments to the enclosed combustor manufacturer test protocol in the NSPS to align it with a similar protocol in the Oil and Natural Gas National Emission Standards for Hazardous Air Pollutants (NESHAP) (40 CFR 63, subpart HH).

I. Annual Report and Compliance Certification

We finalized amendments to allow 90 days after the end of the compliance period for submittal of the annual report and compliance certification.

IV. Summary of Significant Changes Since Proposal

Section III summarized the amendments to the 2012 NSPS that the

EPA is finalizing in this rule. This section will discuss the key changes the EPA has made since the April 12, 2013, proposal. These changes are the result of the EPA's consideration of the many substantive and thoughtful comments submitted on the proposal and other information received since proposal. We believe that the changes we have made sufficiently address concerns expressed by commenters and improve the clarity of the rule while improving or preserving public health and environmental protection required under the CAA.

A. Group 1 Storage Vessel Affected Facility Control Requirements and Applicability

We received comments requesting clarification regarding Group 1 storage vessel affected facility control requirement applicability. We also received comments on our estimate of the supply of combustors used to comply with the control requirements and our use of this estimate to determine the requirements for Group 1 storage vessel affected facilities.

To the extent that there was confusion regarding the applicability of Group 1 storage vessel affected facility control requirements, we agree that there is a need for more clarity in the final amendments. To accomplish this, we have included amendments to § 60.5395(b) that make it clear that these requirements apply only to Group 1 storage vessel *affected facilities* (emphasis added) (*i.e.*, those that have the PTE of 6 tpy VOC or more, as determined by the dates specified in the rule, as amended), not all Group 1 storage vessels. Refer to section V.A of this preamble for further discussion of comments and responses pertaining to these changes.

In the proposed amendments, based on the information then available to the EPA, we concluded that control supply would not catch up with its demand under this rule until 2016. To avoid delaying control until such time, we proposed that Group 1 affected facilities notify the EPA of their presence and location by October 15, 2013, but need not comply with the 95 percent reduction requirement unless they experience an emission increase event. Information we received since proposal indicate that the combustor suppliers have the manufacturing capacity to meet the demand posed both by this regulation and a variety of state and local regulations that require the installation of control devices even when accounting for the need to cover Group 1 well in advance of the projected 2016 date. Therefore, in the final amendments we did not finalize the proposed requirement for Group 1 storage vessel affected facilities to be controlled only if there is an emission increase event. However, as explained in more detail below, we have concerns regarding the projections of potential combustor supply; the pace at which the combustor manufacturing industry can ramp up production and provide the necessary supply in the short-term; and the availability of trained personnel to install these devices on all affected facilities that will have already come on line by the current compliance date of October 15, 2013, as well as the additional approximately 1,100 new affected facilities per month that may need control. Consideration of these factors leads us to conclude that an adjustment to the compliance schedule is warranted.

First, we note that there is a great variability in the projections of potential combustor supply, with one supplier's projection greatly exceeding the other suppliers' projections. Our revised conclusion regarding supply of control devices is largely based on this one supplier's manufacturing capacity, which, if changed, could potentially affect sources' ability to acquire and install control by the current compliance deadline (*i.e.*, October 15, 2013 or 60 days after startup, whichever is later). In light of the above, additional time is needed beyond October 15, 2013, for compliance with the 95 percent reduction requirement. Secondly, we share the concern raised by several commenters that, due to the large number of storage vessel affected facilities, some may not be able to secure the necessary trained personnel to install control devices by the current compliance deadline, especially in the near term. Under the 2012 NSPS, installation of controls would be required by the current compliance date of October 15, 2013, for over 20,000 affected facilities that we estimate will have already come on line since the August 23, 2011, proposal date of the 2012 NSPS, as well as the additional approximately 1,100 new affected facilities per month that will need to install control 60 days after start-up. Lastly, while the overall supply of combustors appears to be adequate, we have concerns about how quickly the combustor manufacturing industry can ramp up production and provide the necessary supply in the short-term. We are doubtful that, even at full current capacity, there would be sufficient control devices to meet the October 15, 2013, compliance date. For the reasons stated above, we decided to take a phase-in compliance approach that requires the newer affected facilities (which would have higher emissions) to comply first. Accordingly, the final amendments require that Group 2 affected facilities comply with the emission standards by April 15, 2014, as we proposed, and that Group 1 affected facilities comply by April 15, 2015.

Refer to section V.C of this preamble for further discussion regarding these changes.

In addition, we had proposed a list of examples of "events" that would trigger control requirements for Group 1 storage vessel affected facilities. As noted, all Group 1 storage vessel affected facilities must meet the control requirements by April 15, 2015. Therefore, we no longer need to look to events that may be presumed to increase emissions to determine which Group 1 storage vessel affected facilities are subject to control requirements. All proposed provisions related to tracking events have been removed from the final amendments, thereby simplifying the rule and avoiding additional burden and potential confusion.

Refer to section V.A of this preamble for further discussion regarding these changes.

B. Applicability Dates and Compliance Dates

As discussed in section IV.A of this preamble, the EPA previously concluded that there will be an insufficient supply of combustion control devices for all storage vessel affected facilities until 2016, based on information available at proposal. To avoid postponing control for all storage vessels affected facilities until 2016, we proposed alternative measures for Group 1 and Group 2 storage vessel affected facilities. For Group 1 storage vessel affected facilities, we proposed to require initial notification by October 15, 2013, to inform regulatory agencies of the existence and location of these storage vessels. We also proposed that Group 1 storage vessel affected facilities that undergo an event after April 12, 2013, that could reasonably be expected to lead to an increase in VOC PTE would be subject to control requirements. For Group 2 storage vessel affected facilities, we proposed April 15, 2014, as the compliance date for implementing control requirements.

In response to comments concerning Group 1 storage vessel control requirement applicability and compliance being tied to the "events" listed in § 60.5395(b)(2) and unclear notification and compliance dates for both Group 1 and Group 2 storage vessels, we have made changes to the

final amendments. For Group 1 storage vessels, we are requiring that the owner or operator determine whether the storage vessel is an affected facility no later than October 15, 2013. In the proposed amendments, owners or operators of Group 1 storage vessel affected facilities had to submit an initial notification of these storage vessels by October 15, 2013, as well as an initial annual report by January 15, 2014. In the final amendments, the initial notification may be combined with the initial annual report to reduce the burden of submitting two notifications within a 90-day period. As discussed previously in section IV.A of this preamble, the final amendments retain the requirement in the 2012 NSPS that all Group 1 storage vessel affected facilities comply with emission standards, and specify that compliance must be achieved by April 15, 2015. Therefore, we have removed all provisions related to tracking emission increase events from the final amendments.

For Group 2 storage vessel affected facilities, we are finalizing April 15, 2014, (or 60 days after startup, whichever is later) as the compliance date for implementing control requirements.

Refer to section V.A of this preamble for further discussion of comments and responses regarding these provisions.

C. Definition of Storage Vessel Affected Facility

We proposed to amend the definition of "storage vessel affected facility" to specify that the storage vessel must have a VOC PTE equal to or greater than 6 tpy to be an affected facility and to clarify that the owner or operator can take into account any legally and practically enforceable emission limit in an operating permit, or by another mechanism under state, local or tribal authority, when determining the VOC PTE. The proposed amendment also clarified that a storage vessel affected facility whose potential VOC emissions decrease to less than the threshold of 6 tpy would remain an affected facility. We proposed this amendment to clarify that a storage vessel complying with the proposed uncontrolled actual VOC emission rate would remain an affected facility.

We received comments opposing the revisions to the definition of "storage vessel affected facility" to the extent that it may allow storage vessel operators to account for non-federally enforceable emission limitations that may change in the future and are not enforceable by the EPA in the determination of VOC PTE. Upon evaluation, we believe that the commenters' concern arises from language we used in the proposed amendments to § 60.5365(e) to define the storage vessel affected facility which could have been confusing due to the phrase "other mechanisms." Therefore, the final amendments clarify that "other mechanisms" must be legally and practically enforceable under federal, state, local or tribal authority.

We received public comments that requested that the 6 tpy threshold for storage vessel affected facilities be determined after application of a vapor recovery unit (VRU) (i.e., taking the VRU vapor recovery into account in the emissions determination) for Group 1 and Group 2 storage vessels.

In September 2012, in response to issues brought to the EPA's attention after the publication of the 2012 NSPS, we clarified that we do not consider VRUs that route recovered gas and vapor back to the process to be control devices, which is consistent with their treatment under 40 CFR part 63, subpart HH.[2]

As long as certain operating requirements are met, we believe it is appropriate to take into account reductions in VOC emissions that result from the recovery of vapor and routing of it to a VRU when determining the VOC PTE from a storage vessel for purposes of determining affected facility status. Routing of vapor through a VRU to a process reduces VOC emissions without secondary environmental impacts (*e.g.*, NO_X emissions) and is responsible conservation of our energy resources. However, it does not totally eliminate VOC emissions, since the VRU cannot operate 100 percent of the time due to maintenance and repair down time. Our September 28, 2012, letter clarified that the cover and closed vent requirements must be met when VRU is used to meet the 95 percent reduction emission standards. That said, we previously determined that routing of vapor through a cover and properly operated closed-vent system would recover all vapor routed to the system as long as the VRU is operating (*i.e.*, 95 percent of the vapor being routed to a line when operating for 95 percent of the time). In light of the above, as long as the VRU is operated consistent with those requirements, we believe that it is appropriate to exclude 95 percent of the vapor that would otherwise be emitted if not recovered when determining PTE for purposes of determining affected facility status. As a result of this comment, and based on our prior clarification of this issue, the final amendments to § 60.5365(e) include a provision that "any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status." Further, we have added language to § 60.5365(e) that provides for this adjustment of PTE as long as (1) the storage vessel is operated in compliance with cover requirements in § 60.5411(b) and the closed-vent system requirements in § 60.5411(c), which has a requirement that the CVS (including the VRU) is operational at least 95 percent of the time, and that the operator maintain records demonstrating compliance with these requirements.

We were concerned that, should a VRU be removed or operated inconsistent with the conditions that were the basis for the PTE reduction following the PTE determination for assessing whether the storage vessel is an affected facility, emissions could increase without the storage vessel being subject to control. To address that possibility, we have added language to § 60.5365(e) such that, in the event of removal of apparatus that recovers and routes vapor to a process or operation that is inconsistent with the conditions for qualifying for the PTE reduction, the owner or operator would be required to determine PTE from the storage vessel within 30 days of such removal or operation. If the PTE is determined to be 6 tpy VOC or more, then the storage vessel would be an affected facility and subject to the control requirements in § 60.5395. We believe this approach will help avoid circumvention of the NSPS.

We received comment that storage vessel affected facilities that are removed from service should cease to be considered affected facilities. Although, for the reasons presented in section V.C of this preamble, we disagree with the commenter and have added language at § 60.5395(f) to address storage vessel affected facilities that are removed from service. Owners and operators are required to include a notification in their next annual report following removal from service that the storage vessel has been taken out of service. If a storage vessel's return to service is associated with the fracturing or refracturing of a well feeding the storage vessel, the storage vessel is subject to control requirements immediately upon returning to service. If, however, the storage vessel's return to service is not

[2] Letter from Peter Tsirigotis to Matthew Todd, American Petroleum Institute. September 28, 2012. Docket Item No. EPA–HQ–OAR–2010–0505–4595.

associated with well fracturing or refracturing, the PTE of the storage vessel must be determined within 30 days. If the PTE is 4 tpy or greater, then the storage vessel affected facility must comply with control requirements within 60 days of returning to service.

V. Summary of Significant Comments and Responses

This section summarizes the significant comments on our proposed amendments and our response thereto.

A. Major Comments Concerning Applicability Dates and Compliance Dates

1. When do Group 1 storage vessels have to determine emissions?

a. Applicability Determination

Comment: One commenter requested that the final rule specify the date upon which the determination of the potential VOC emission rate should occur for the purpose of determining whether the storage vessel is an affected facility. According to the commenter, since the EPA has stipulated controls to not be cost effective for storage vessels emitting less than 6 tpy of VOC, and emission rates for storage vessels in the oil production segment tend to decrease as production declines, the commenter believes the determination should be made near to the date upon which controls would be required in order to minimize the potential to install controls on storage vessels for which production decline has rendered controls no longer cost effective. The commenter stated that the proposed revisions would require a determination by October 15, 2013, of whether individual Group 1 storage vessels are affected facilities, and thus October 15, 2013, would be an appropriate date upon which determination of the potential VOC emission rate should be based. According to the commenter, this would remain consistent with the requirement for determining the potential VOC emission rate for Group 2 storage vessels by April 15, 2014 or 30 days after startup, whichever comes later.

The commenter appears to suggest that, like Group 2, Group 1 storage vessel affected facilities located in the natural gas processing and natural gas transmission and storage segments should also be required to determine potential VOC emissions as the trigger for installing control instead of tracking events but to do so by April 15, 2015 (instead of April 15, 2014, proposed for Group 2). According to the commenter, control of the relatively low number of Group 1 storage vessel affected facilities in these segments could likely be accommodated by this date.

Another commenter pointed out that the proposed reconsideration rule does not establish the date for a Group 1 storage vessel to determine its potential emissions. The commenter also recommended that notifications are only required for tanks that exceed the 6 tpy threshold on October 15, 2013. Although the publication date of the proposed reconsideration rule was April 12, 2013, the commenter contends that the EPA is not required to, nor should it, establish the emissions determination date for the source category of Group 1 storage vessels on that date. First, given the rapidly declining emissions at storage vessels following initial fracturing, the commenter believes that the expected emissions reduction to be gained from Group 1 storage vessels is likely to be limited. The commenter also states that the proposal date of April 12, 2013, has passed and operators may not be able to accurately back-calculate emissions from that date. Moreover, the commenter contends that emissions from many of these storage vessels will be below the 6 tpy affected source threshold as of October 2013. Given EPA's proposed approach, where storage vessel affected facilities whose emissions drop below 6 tpy remain subject to the standard, the commenter believes that many Group 1 storage vessels will be unnecessarily captured in the source category and required to indefinitely track "events" and perhaps install control devices even if their emissions never again exceed 6 tpy.

Response: The final amendments to § 60.5365(e) specify that Group 1 storage vessel affected facilities must determine potential VOC emissions by October 15, 2013, for purposes of determining whether it is an affected facility. For the reasons provided in the Response to Public Comments on the Proposed Amendments document available in the docket, the final amended § 60.5365(e) requires that Group 1 affected facilities submit a notification with the first annual report by January 15, 2014, to inform regulatory agencies of their existence and locations. Determining potential emissions and affected source status early on is not only necessary for Group 1 affected facilities to comply with the notification requirement by January 15, 2014,[3] it will also provide Group 1 affected facilities advance notice and time to secure the necessary control devices and schedule the installation personnel to perform the installation by April 15, 2015. We reject suggestions by some commenters that emission determination be conducted closer to the deadline for installing control because such delay would frustrate the reason for extending the compliance date for Group 1 affected facilities in the final amendments (i.e., to provide advance notice and time to secure the necessary control devices and schedule the installation personnel to perform installation). Further, the commenters apparently assumed, though incorrectly, that the EPA has concluded that control is not cost effective when VOC emissions are below 6 tpy. No such determination has been made by the EPA or demonstrated by commenters. On the contrary, as discussed in section V.C of this preamble, we have determined that continuing control at uncontrolled emission rates of 4 tpy or above is cost-effective. For the reasons stated above, the final amendments specify October 15, 2013, as the deadline for determining the VOC PTE for Group 1 storage vessels. If the VOC PTE of the Group 1 storage vessel is 6 tpy or greater on October 15, 2013 (or an earlier date if the owner or operator chooses to make the determination prior to October 15, 2013), then the storage vessel is a Group 1 storage vessel affected facility and is subject to the NSPS, which for Group 1 includes the notification requirement by January 15, 2014 (i.e., the date by which the first annual report is due), and the control requirement by April 15, 2015. We are not finalizing the proposed requirement that Group 1 storage vessels track events that may increase the VOC PTE of the storage vessel (refer to section V.A of this preamble) and install control should there be such event; this proposed Group 1 storage vessel requirement is no longer necessary since the final amendments retain the control requirement for all Group 1 storage vessel affected facilities.

One of the commenters expressed concern that Group 1 storage vessels will have to indefinitely track events for these storage vessels and install controls even if VOC emissions do not exceed 6 tpy. The final amendments do not include requirements for owners and operators to track events for Group 1 storage vessels, so this comment is now moot.

The EPA does not believe it is necessary to defer the date at which Group 1 storage vessels located in the natural gas processing and natural gas transmission and storage segments are required to determine emissions. The commenter was suggesting an

[3] We had proposed to require such notification by October 15, 2013, but, in response to comment, we have extended this deadline slightly to January 15, 2014, to allow Group 1 affected facilities to submit the notification with their annual report instead of separately.

alternative to tracking events for storage vessels in these segments, and the final amendments do not include the proposed event tracking provisions.

b. Determination After an Event

Comment: One commenter sought clarification that the requirement to re-estimate emissions when there is an event that could reasonably be expected to increase emissions does not apply to non-affected facilities. Two commenters requested that the EPA specify whether the VOC emissions increase for Group 1 storage vessels are to be based on potential or actual emissions. Another commenter suggested that the EPA clarify that the baseline emissions used to determine whether a Group 1 storage vessel experiences an emission increase is the level of emissions immediately prior to the event.

Response: In the final amendments, we have removed the requirement to track events for Group 1 storage vessels (refer to section IV.A of this preamble). Therefore, these concerns are now moot.

2. Which Group 1 storage vessels are subject to the initial notification requirements and when are the notifications due?

Comment: One commenter states that the definitions for "Group 1 storage vessel" and "storage vessel" in § 60.5430 do not contain the 6 tpy threshold required for a "storage vessel affected facility" under § 60.5365(e). The commenter believes that the EPA's intent is to only be notified by October 15, 2013, of Group 1 storage vessels that exceed 6 tpy and for operators to monitor these vessels for a subsequent "event" because any storage vessel under 6 tpy is not an affected facility and therefore should not be subject to requirements under the rule. The commenter further states that in § 60.5395, the heading which premises paragraph (b)(1) states, "You must comply with the standards in this section for each storage vessel affected facility." The commenter asserts that, based on the definition of Group 1 storage vessel and the order of requirements in the above provisions, this requirement could be misinterpreted to mean that all storage vessels between those specified Group 1 dates must be reported, regardless of their PTE.

Another commenter agreed, stating that none of the storage vessel definitions contains the 6 tpy threshold that is included in the § 60.5365(e) definition of "storage vessel affected facility." The commenter added that, as proposed, § 60.5395(b) seems to include requirements for "Group 1 storage vessel affected facilities" but the notification and event requirements in proposed § 60.5395(b)(1) and (2) apply to "Group 1 storage vessels" rather than "Group 1 storage vessel affected facilities." The commenter believes that these requirements may be misinterpreted to apply to all storage vessels containing an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, regardless of whether their potential emissions meet the 6 tpy threshold.

Response: As proposed, § 60.5395(a)(1) states that owners or operators of Group 1 storage vessel affected facilities must comply with paragraph § 60.5395(b). The commenters are correct in their interpretation that the § 60.5395(b) requirements apply only to Group 1 storage vessel affected facilities (i.e., those Group 1 storage vessels with potential VOC emissions of 6 tpy or more), not all Group 1 storage vessels. For clarity, we have moved the affected facility determination requirements from § 60.5395 to § 60.5365(e) and have only requirements that apply to affected facilities now in § 60.5395. The final amendments to § 60.5365(e) clarify our intent.

We also proposed in § 60.5395(b) that owners or operators submit the initial notification of Group 1 storage vessel affected facilities by October 15, 2013. As discussed in section V.A of this preamble, the final amendments require that owners or operators determine the VOC PTE of Group 1 storage vessels by October 15, 2013, and submit the initial notification for Group 1 storage vessel affected facilities, which may be included in the first annual report, by January 15, 2014. The provisions in the final amendments to allow the initial notification of Group 1 storage vessel affected facilities to be submitted with the initial annual report are discussed further in the Response to Public Comments on the Proposed Amendments, available in the docket.

3. Group 1 Storage Vessels That Become Affected Facilities on or After April 12, 2013

Comment: One commenter requested that Group 1 storage vessels that experience a triggering event should follow the same schedule for Group 2 storage vessel affected facilities to install controls (by April 15, 2014, or 60 days after startup, whichever is later), except that there could be a hard deadline for Group 1 storage vessel affected facilities along a natural gas pipeline. The commenter pointed to the preamble of the proposed amendments (FR 78 22131) that indicates the EPA's intent was for Group 1 storage vessel affected facilities, after a triggering event, to become subject to the same control requirements as those in Group 2, and that these controls would be required no later than 60 days after the event, or April 15, 2014, whichever is later. According to the commenter, this intent was overlooked in the proposed rule amendments.

Two commenters added that the final rule should specify a compliance period for Group 1 storage vessels that originally had potential VOC emissions less than 6 tpy and subsequently experience an event that causes the potential VOC emission rate to meet or exceed 6 tpy. In such cases, the commenters requested that the storage vessel should be required to achieve compliance within 60 days after the event.

Another commenter contended that almost all events that would increase emissions at Group 1 storage vessels are planned or are of a foreseeable nature. The commenter believes that it is feasible for storage vessel operators to install and operate controls simultaneously with the occurrence of such planned events. The commenter added that because emissions from storage vessels are likely to be highest immediately after the events listed in 60.5395(b)(2), it is also essential for protection of public health that controls be implemented as soon as possible.

Response: As explained in section IV.A of this preamble, the emission standards remain applicable to all Group 1 affected facilities, as in the 2012 NSPS. Accordingly, we are not finalizing the proposed requirement to track emission increase events and meet the control requirement as a result of such events for Group 1 storage vessels affected facilities. Thus, comments/issues relative to compliance schedule for Group 1 storage vessel affected facilities that experience an event are now moot.

B. Major Comments Concerning the Storage Vessel Affected Facility Definition

Comment: In the reconsideration proposal, the EPA proposed to include a VOC emissions threshold of 6 tpy to determine, in part, which storage vessels are affected facilities. Additionally, the proposal allowed operators to take into account requirements under a legally and practically enforceable limit in an operating permit or by other mechanism. One commenter opposed this proposal to the extent that it allows storage vessel operators to account for non-federally enforceable emission limitations. According to the

commenter, the inclusion of non-federally enforceable limitations leads to oversight concerns, and some storage vessels would avoid the NSPS under the proposed threshold.

Additionally, the commenter maintains that the CAA does not allow "synthetic minor" programs to determine applicability of its NSPS regulations. The commenter states that the term "potential to emit" is not found in section 111 of the CAA but is a concept from CAA programs governing expressly defined major sources. As a result, the commenter states that the CAA does not specify that a minor source program run by the states or other entities should be a means to avoid NSPS regulations. According to the commenter, allowing non-federally enforceable standards to exempt sources from NSPS is problematic because states vary widely in the letter, implementation, and enforcement of their synthetic minor programs.

Response: In the preamble to the proposed amendments we stated that our intent was that "a source can take into account any legal and practically enforceable emissions limit under federal, state, local or tribal authority when determining the VOC emission rate for purposes of [the 6 tpy] threshold" (78 FR 22132). The language we used in the proposed amendments to § 60.5365(e) to define the storage vessel affected facility allows the owner or operator to "tak[e] into account requirements under a legally and practically enforceable limit in an operating permit or by other mechanism." We agree with the commenter in so much as the term "other mechanism" may be construed to include non-federally enforceable mechanisms that may have questionable, if any, enforceability provisions. Therefore, the final amendments removed the term "other mechanisms" and revised the provision to allow the owner or operator to "tak[e] into account requirements under a legally and practically enforceable limit in an operating permit or requirement under a Federal, state, local or tribal authority." We believe that the amendment clarifies only legally and practically enforceable limits can be considered when a source determines its PTE. The EPA's ability to require Federal enforceability rather than just legal and practical enforceability has been an issue since the DC Circuit decision in *National Mining Assn.* v. *EPA*, 59 F.3d 1351 (D.C. Cir. 1995). As we have yet to address this remand/vacatur, the agency does not feel at this time that it can dictate Federal enforceability in this context.

Concerning the comments on our use of PTE as an applicability threshold, that was based on our BSER determination made in the 2012 NSPS taking into account the control's cost effectiveness. Section 111(a)(1) of the CAA specifically identifies cost of achieving reduction as a factor to consider in setting NSPS standards. Nothing in section 111 of the CAA prohibits the EPA from using PTE to reflect our cost consideration in establishing applicability thresholds under section 111. Petitioner failed to explain how the fact that PTE is often used in connection with determining major source status in other provisions of the CAA bars its use for determining applicability status under section 111.

C. Major Comments Concerning Storage Vessel Control Requirements

1. CAA Section 111 Requirements

Comments: According to one commenter, section 111 of the CAA is fundamentally a technology-forcing provision that can and should be used to spur aggressive deployment of emission control technologies. The commenter contends that standards are to be set stringently, in order to force the development of new technology. If the EPA must phase in controls, and can otherwise justify such an approach under section 111, the commenter believes the EPA must do so in as limited a way possible, ensuring it does not disrupt incentives which would otherwise expand pollution control development.

The commenter added that the courts have clarified that EPA's selection of BSER is only limited by cost when industry demonstrates an "inability to adjust itself in a healthy economic fashion to the end sought by the Act as represented by the standards prescribed." Further, the commenter states that creating deferrals meant to track control equipment supply is not technology-forcing, but market-following. According to the commenter, this ignores the role of standard-setting in incentivizing higher production of control equipment. If EPA cites availability of control devices in deferring or reducing the stringency of an NSPS, the commenter contends that the EPA must offer a strong demonstration that supply constraints render the standard unachievable or prohibitively expensive for the industry as a whole.

Response: As explained in section IV.A of this preamble, the EPA proposed to phase in the control requirement for storage vessel affected facilities based on its belief at the time that there would not be enough control devices to meet the demand of all storage vessel affected facilities by the October 15, 2013, compliance date in the 2012 NSPS or any time in the near future. Although new information received since our proposal indicates that control supply may not be an issue, the EPA is phasing in the storage vessel control requirement in the final amendments for the reasons provided in section IV.A. The phase-in approach has never been based on cost, as the commenter suggests; rather, as indicated in section IV.A of this preamble and in the preamble to the April 12, 2013, reconsideration proposal, the phase-in approach is intended to avoid setting a control requirement that cannot be met due to limitations associated with installing control devices. We do not believe that a standard that ignores such limitations accurately represents the BSER for these affected facilities.

2. Group 1 Requirements

a. No Control of Group 1 Storage Vessels

Comment: According to one commenter the proposal to exempt Group 1 storage vessels that do not experience increases in emissions rests on questionable projections of estimated current and future supply of control devices, number of storage vessels and decline of oil and natural gas well production. The commenter contends that the EPA cited only unidentified oil and gas industry sources for the asserted level of control device production and provided no justification for forecasted rate of production increase or the production rate plateau of 1,400 units per month. The commenter believes that it is as or more likely that industry would continue to expand control device production in response to the proposed standards, but the proposed delays would slow control manufacture by removing demand. According to the commenter, the EPA could remove its artificial ceiling for control manufacture and accelerate the compliance deadline for Group 2 storage vessels and require most or all Group 1 storage vessels to control emissions by mid-2015. The commenter contended that the EPA must disclose the information underlying these forecasts to allow the public to evaluate their reasonableness and offer comments.

The commenter added that the assumption of one storage vessel per well overestimates the number of new storage vessels and is unjustified. The commenter provided examples of increased use of multi-well pads.

According to the commenter, the EPA uses the fact that oil and gas wells

decline in production over time as justification for exempting Group 1 storage vessels from control requirements. The commenter states that the EPA's forecast of control equipment availability implies no reduction in the number of storage vessels requiring control. This is contrary to the justification given for exempting Group 1 storage vessels from control requirements. According to estimates of a decline in production, the commenter believes that some Group 1 storage vessels could remain a significant source of emissions.

The commenter also contended that the EPA's projections indicate that the supply of existing control devices will be adequate to meet the combined demands of Group 1 and 2 storage vessels by 2016. It is not clear to the commenter what portion of the estimated 20,000 Group 1 storage vessels would ultimately be subject to control, so it is unclear whether subpart OOOO would ever apply to those Group 1 storage vessels with high emissions. Even assuming that emissions from these Group 1 storage vessels generally continue to decline over their remaining lives, the commenter believes that allowing this group of storage vessels to be uncontrolled would result in a large amount of excess emissions relative to the current rule. Conservative estimates by the commenter indicate that the proposal to leave Group 1 storage vessels unregulated would allow over 3 million tpy VOC and 700,000 tpy of methane to be emitted. Taking into account the production decline, the commenter contends that an analysis of the Bakken shale formation indicates that in 2015 storage vessels could still be emitting about 30 percent of their initial emissions. For the reasons given above, the commenter believes that the Group 1 storage vessel exemption is arbitrary and falls short of section 111 mandates that standards of performance reflect BSER.

The commenter further contended that if EPA's analysis indicates a sufficient supply of control devices will be available in the future, then Group 1 storage vessels should be controlled within a reasonable time. The commenter states that a compliance deadline in mid 2015 would provide adequate time for all storage vessels currently subject to the proposed rule to come into compliance. To support this view, the commenter reasons that, if some fraction of the Group 1 storage vessels will no longer have emissions exceeding 6 tpy, the demand for control devices is likely to be lower than the EPA's projections, given the opportunities to manifold closely-spaced storage vessels, the increased practice of multi-well pads which would share storage vessels, and the EPA's statement in the preamble to the proposed rule that control device manufacturers are likely to be flexible in their ability to meet equipment demand increases in the future.

Another commenter agrees that an alternate compliance schedule is necessary to accommodate the increased demand for control devices but recommended that Group 1 storage vessels that continue to have emissions greater than 6 tpy as of the Group 2 compliance date be required to comply with the control requirements of the rule.

Several commenters express concern that the increased demand for control devices will lead to delays in getting the devices installed and that additional time to comply with the proposed standards is required. One commenter states that the companies that supply the services to comply with the proposed amendments will have their time monopolized by the large oil and gas companies, leading to a shortage of these services for small oil and gas companies. Another commenter similarly expresses concern that small independent producers will experience a shortage of service personnel because the smaller producers have less leverage and buying power than large producers.

Response: In the preamble to the proposed amendments, we discussed our rationale for requiring controls only on those Group 1 storage vessel affected facilities that have an event that would likely lead to an increase in the potential to emit VOC (78 FR 22130). Our decision to require controls only on Group 1 storage vessels that experience such an event was based, in large part, on our understanding at that time and the information then available of the supply of combustors that likely would be used to comply with the control requirements. As we understood the combustor manufacturing industry at the time of proposal, the total capacity to produce combustors was approximately 300 units per month, which was based on information from six combustor manufacturers, and that the industry had the capability of increasing that capacity by about 100 units per month.

In response to comments questioning our combustor supply analysis, we reassessed the production capacity of the combustor manufacturing industry. We were able to confirm the data for some of the six manufacturers for which we had data at proposal, which leads us to believe the data as a whole for these manufacturers are reasonable (*i.e.*, current capacity on average of about 600 units per year for each company). In addition, we were able to identify five additional combustor manufacturers. Of these five, three provided production capacity estimates that were in line with the data we originally had for the six companies, one provided production estimates that were significantly higher than any of the other companies, and one did not provide any data. We averaged the production capacity of the nine similar companies to complete the missing data from the one facility that did not provide data. We then summed the capacity of these 11 companies to determine total current manufacturing capacity of combustors, which was approximately 2,300 units per month.

We also estimated future capacity of the combustor manufacturers based on information provided by the manufacturers for anticipated future increases in production capacity. Based on this information, we estimated future capacity to be as high as approximately 3,000 units per month by April 15, 2015.

The new information described above (for further details, see the memorandum entitled *Combustor Supply and Demand Analysis*, available in the docket) seems to indicate that the combustor suppliers have the manufacturing capacity to meet the demand posed by all (*i.e.*, both Group 1 and Group 2) storage vessel affected facilities required to comply with emission standards in the 2012 NSPS. Therefore, in the final amendments, we continue to require that Group 1 storage vessel affected facilities comply with the emission standard requirements. However, we have extended the current compliance deadline for the reasons stated below.

While the overall projected supply of combustors appears to be adequate, we do not have information as to whether the combustor manufacturers are producing at the projected capacity and, if not, how quickly they can ramp up production to provide the necessary supply for the 2012 NSPS. More importantly, we note that there is a great variability in the projections of combustor supply, where one supplier's projection greatly exceeds the other suppliers' projections and accounts for a significant portion of the supply. To gauge the sensitivity of this one company on the combustor supply, we revisited our supply analysis assuming this company could manufacture combustors only at the highest manufacturing rate reported by any of the other combustor manufacturers. We found that under this scenario the supply of combustors never satisfies the

demand. Thus, this one manufacturer is critical in meeting the overall demand imposed by the 2012 NSPS.

Because this company plays such an important role in meeting the combustor supply, any factor that may delay or slow their production may significantly affect the ability of Group 1 and Group 2 storage vessel affected facilities to achieve compliance by the current compliance deadline in the 2012 NSPS (*i.e.*, October 15, 2013, or 60 days after startup, whichever is later). In light of the above, we believe it is prudent to allow more time for compliance to lift the pressure on the demand of control devices, especially in the short term. Under the 2012 NSPS, compliance is required by October 15, 2013, for an estimated over 20,000 storage vessel affected facilities that will have come on line since the August 23, 2011, (the proposal date of the 2012 NSPS), and an additional 1,100 new affected facilities per month will need to install control 60 days after start-up. Extending the current compliance deadline would allow the market to more easily absorb any events that may cause combustor manufacturing to fall short of the projected production capacity.

In addition to the supply issues described above, commenters raise the concern about not being able to secure the necessary trained personnel to install control devices by the current compliance deadline. In light of the large number of storage vessel affected facilities (estimated over 20,000 by October 15, 2013, with an additional 1,000 per month after that), and given the wide geographic distribution of oil and gas wells across the United States, we believe that the commenters raise a legitimate concern. In particular, we are concerned about how a potential shortage of trained personnel may impact small businesses. The comments we received indicate that larger owners and operators may be able to garner the majority of the available installation personnel due to their greater resources and influence. This may result in a situation where small owners and operators may be placed in a disadvantage to their larger competitors in obtaining installation personnel. If such a situation should occur, the smaller owners and operators may be forced to shut down wells or delay drilling new wells until installation personnel are made available.

In light of the issues described above that may hinder storage vessel affected facilities' ability to comply by the current October 15, 2013, deadline, we do not believe it is reasonable to retain that compliance date. Instead, in the final amendments, we take a phase-in compliance approach that first addresses newer affected facilities (which would have higher emissions) while assuring that all affected facilities have time to acquire and schedule installation of control. The final amendments establish Group 1 and Group 2 affected facilities, as proposed, where Group 1 are those affected facilities that came on line on or before April 12, 2013, and Group 2 are those that come on line after that date. The final amendments require that Group 2 comply by April 15, 2014 (or 60 days after start-up, whichever is later), a 6-month extension from the current October 15, 2013, deadline for these newer affected facilities. The final amendments require that Group 1 comply by April 15, 2015. Were we to require that both groups comply by April 15, 2014, an estimated 30,000 affected facilities would be competing to acquire and install control by that date; as a result, the 6 month extension would do little to ease the demand for control or skilled personnel to install control should either become an issue in the near future. Also, requiring Group 1 to comply by April 15, 2014 would likely affect Group 2's ability to comply, thus undermining our goal to address the newer storage affected facilities sooner. Lastly, considering the large number of Group 1 affected facilities (which we estimate to be around 19,400), we believe that requiring all Group 1 affected facilities to comply by April 15, 2015 is reasonable. In light of the issues discussed above, we do not expect that these affected facilities would wait until near that deadline and risk noncompliance; rather, we believe that the deadline provides Group 1 advance notice and allows them time to plan for acquiring and scheduling installation of control device by that date. Therefore, in the final amendments, we have specified that all Group 1 storage vessel affected facilities must comply by April 15, 2015, and that Group 2 storage vessel affected facilities must comply by April 15, 2014, or 60 days after startup, whichever is later.

b. Clarification of "Events" That May Increase Emissions

Comment: Several commenters request that the EPA more clearly define the types of events that would trigger emission increases for Group 1 storage vessels. Seven commenters request that the EPA limit the examples to a finite list of events to remove ambiguity. One commenter states that the "events" that trigger control requirements for Group 1 tanks should be more specific for storage vessels at well sites. According to the commenter, only the events described in § 60.5395(b)(2)(i) through (iii) of the proposed amendments should be considered triggering events for storage vessels that store reservoir fluids (*i.e.*, at well sites, tank batteries, centralized production facilities).

One commenter requested that the EPA delete the list of examples of events that would increase emissions from the rule language and provide that control requirements are triggered by a change that, in the owner's/operator's judgment, is one that could reasonably be expected to increase VOC emissions.

One commenter suggests that the EPA should clarify the illustrative list of emission-increasing events to include well maintenance activities, such as liquids unloading, various well workover procedures, and any other well maintenance activities which increase production.

Response: As discussed in section IV.A of this preamble, the final amendments do not change the requirement in the 2012 NSPS that all storage vessel affected facilities, including those we define as Group 1 affected facilities, to meet the emission standards, although the amendments extend the time for compliance. Since all Group 1 storage vessel affected facilities remain subject to control requirements, there is no need to track events in order to determine which Group 1 storage vessel affected facilities are subject to control requirements, we are not finalizing the proposed provisions related to events in the final amendments.

c. At what emission rate are Group 1 storage vessels that experience an event required to install controls?

Comment: Three commenters request that the EPA clarify that Group 1 storage vessels that experience an event that results in an increase in emissions would not be required to install controls if the VOC emissions are below the 6-tpy emission threshold. Two commenters recommend that the 6 tpy threshold be included either in the definition of "Group 1 storage vessels" in § 60.5430 or be explicitly listed as a condition in the requirement under § 60.5395(b)(1).

One commenter states that if emissions from a Group 1 storage vessel affected facility decrease below 6 tpy due to production decline, and it was determined even after a potentially triggering event that emissions had not returned to a level above 6 tpy, the storage vessel should not become subject to Group 2 controls. This view is generally supported by two additional commenters. The commenter refers to § 60.5410(i) which specifies that the

requirement for installing Group 2-level controls is further limited to Group 1 storage vessel affected facilities for which the potential VOC emission rate is 6 tpy or greater after the triggering event. According to the commenter, this 6 tpy threshold is reasonable and appropriate because the EPA concluded in the initial rulemaking that Group 2 controls would not be cost effective for storage vessels emitting less than 6 tpy of VOC.

The commenter adds that based on statements in the preamble (78 FR 22132) and regulatory language in § 60.5410(i), this 6 tpy threshold should be repeated in § 60.5395.

Response: As discussed in the previous comment response, the final amendments do not require that Group 1 storage vessels track events. Therefore, these comments are now moot.

3. Alternative 4-tpy Uncontrolled Actual VOC Emission Rate

Comment: One commenter states that the proposed 4 tpy emission rate, below which controls would not be required, is not BSER and would allow large and unjustifiable emissions increases. According to the commenter, the 95 percent control limit ensures that actual emissions do not exceed 0.2 tpy. Under the proposal, a storage vessel could emit up to 4 tpy indefinitely which is nearly a 3.8 tpy increase above the emissions that would be allowed under the proposed NSPS.

According to the commenter, once control devices are removed, it is more likely that unplanned events will cause significant emissions spikes, further increasing air pollution. For example, if an operator diverts a sudden surge of VOC-containing liquids to a storage vessel for which the operator has removed controls under the proposed mass-based limit, there will be no way to control the resulting emissions spike. The commenter contends that the result is that transient but significant emissions events may become more common at storage vessels using the proposed mass-based limits.

The commenter adds that even if it is assumed that the proposed emission rate would apply for a single year of a given group of storage vessels' lives, the proposal would allow tens of thousands of tons of pollution in that year. If storage vessels operate longer, or decline more slowly after passing the 4 tpy threshold, the amount of additional air emissions will be even higher.

The commenter could find no authority in the CAA for abandoning BSER controls after they have been installed. Having already determined that 95 percent control is BSER, the commenter states that the EPA provided no justification of the basic premise or the level of the proposed emission rate. The emission rate has not been demonstrated to alleviate any control device shortage, and control devices that would become available due to the emission rate are unlikely to be available for more than a decade after the proposal is finalized.

The commenter contends that the EPA has not shown that the proposed 4 tpy limit corresponds to BSER. To make such a demonstration, the commenter believes, it would be necessary for the EPA to show that control technology has not been demonstrated below the 4 tpy emission rate, meaning that such sources can properly escape control, or that controls are not cost-effective for the industry as a whole below such an emission rate. According to the commenter, controls clearly are available for storage vessels with emissions of 4 tpy and below, so there is no justification for the 4 tpy emission rate on control technology availability grounds. Additionally, the commenter contends that significant VOC emissions can be captured below the proposed threshold. With respect to cost, the commenter believes recent information indicates the annualized cost of storage vessel combustors has declined substantially since subpart OOOO was finalized, significantly enhancing the cost effectiveness of controlling VOC emissions from storage vessels with a PTE of 4 tpy or less. The commenter provides information from a Colorado Department of Public Health and Environment (DPHE) pending rulemaking showing that the annualized combustor costs are around $15,900/yr, as compared to the previous value of $19,600/yr, resulting in a cost effectiveness of $4200/ton at 4 tpy.

Further, the commenter believes that the EPA's control costs overestimate actual costs because the EPA does not take into account savings that would be experienced when controls are shared among storage vessels. As a result, controls are more affordable at lower uncontrolled emissions thresholds. According to the commenter, if the EPA sets a very low emission threshold at which removal and reuse is permissible, more vessels would have to buy new control devices, raising control costs again. Thus, the commenter believes that the EPA's analysis does not compare this variation, or considered the appropriate way to design such a system in light of the variation.

According to the commenter, the EPA states in the proposal that control device manufacture will lag the growing population of storage vessels for a few years and used this rationale to separately waive controls for Group 1 storage vessels and assure adequate supply of control devices for Group 2 storage vessels. The commenter contends that the EPA further states that allowing affected storage vessels to remove controls under the proposed emission rate would help alleviate the control device shortage. According to the commenter, the EPA's justification that imposing the emission rate is due to uncertainty in their control technology projections and that an additional exemption would "help build a buffer" against this uncertainty is not a cognizable justification for a section 111 standard under the CAA. Further, the commenter does not believe that the EPA has demonstrated either the necessity or appropriateness of the proposed emission rate.

The commenter states that the EPA's concerns about "buffering" technology supply could only justify this departure from the existing standard if the proposed emission rate was also demonstrated to be BSER. According to the commenter, the EPA determined that requiring storage vessels with uncontrolled emissions greater than 6 tpy to achieve 95 percent control of those emissions reflects BSER and is cost effective. The commenter states that if these controls were maintained on a storage vessel as its emissions declined over time, total uncontrolled emissions would continue to fall. But under the proposed emission rate, the commenter contends that emissions could instead jump sharply after the threshold has been crossed. The commenter believes that this reversal in the emissions trend does not reflect BSER because it does not reflect the best demonstrated system of emissions control. According to the commenter, it is instead what happens when BSER controls are removed.

The commenter adds that for the EPA's "buffer" rationale to hold up, operators must be able to cost-effectively and regularly remove used control devices, store them as needed, and transfer them to new storage vessels at a rate which will meaningfully address the control device shortage which the EPA projects. The commenter asserts that the EPA provided no evidence showing operators would be able to do this, or would choose to do so. According to the commenter, storage vessels installed now would in all likelihood not take advantage of the proposal until the 15th year of operation (based on decline curve data provided by the commenter showing that it would take up to 15 years for well production to decline to a level to produce uncontrolled storage vessel emissions of

4 tpy). As a result, the commenter believes that the proposed emission rate would not generate any control devices for transfer for more than a decade, which is long after the EPA estimates adequate control devices will be available. Thus, according to the commenter's analysis, even if control devices could be transferred, such transfers will not buffer a short-term shortage. That shortage, if it exists, will long have passed. Instead, the commenter believes that the proposed emission rate would simply increase air pollution.

The commenter further states that even if the EPA were to actually require operators to build the buffer it desires, the EPA offers no evidence that such a buffer is required indefinitely. Elsewhere in the proposal, the commenter contends, the EPA expresses its view that control device manufacturers will respond to the standards by manufacturing enough control devices to meet the demand imposed by the standards, perhaps after an initial delay. The commenter points out that past experience shows that control devices become available if they are required, and this technology-forcing function is central to how section 111 is intended to work. By instead allowing operators to avoid purchasing new controls, and to remove them from other sources and reuse them, the commenter contends that the EPA permanently limits the market for new control technology, while also allowing excess emissions. The result will be fewer controls in the long-term, and more pollution.

The commenter believes that the Wyoming guidance the EPA mentions in the proposal does not comply with section 111 standards, and contends that the EPA does not offer evidence that it has avoided excess pollution.

Another commenter believes the EPA's choice of an uncontrolled emission rate of 4 tpy as the emission rate is arbitrary and unsupported. The commenter states that the EPA provided no engineering basis, credible health benefit estimate, or other justification for why the 4 tpy emission rate is appropriate.

The commenter also states that the EPA did not provide any justification or analysis demonstrating whether control at 4 tpy is cost effective. The commenter states a cost effectiveness analysis was performed for the 6 tpy applicability threshold, but no such information is provided for the proposed 4 tpy emission rate. The commenter opined that this approach will create situations of great inequity where neighboring facilities may have identical PTE VOC emissions from a single storage vessel or battery, but very different regulatory burdens. The commenter provides an example where a site with emissions of 5.95 tpy is not subject to any of the notification, reporting, or control requirements of this NSPS. However, a neighboring site with initial production emissions of 6.1 tpy must notify, control, monitor, record, and report to comply with the NSPS. The commenter provides that, as natural production declines occur, after a year of uncontrolled emissions of 3.95 tpy (below the 4 tpy threshold) the additional controls may be removed, but the burden of reporting and recordkeeping continues indefinitely for this site.

The commenter also states that this approach may also drive companies to design their sites in a way that results in increased emissions overall, defeating the goal of the rule itself. For example, according to the commenter, to avoid applicability of the rule as a whole, new sites will likely be designed with more tanks such that no single tank will exceed the 6 tpy applicability threshold but emissions from the larger number of small tanks may have higher overall emissions. The commenter believes that this in turn may exacerbate the shortage of storage tanks that already exists and may further delay production due to the lack of tank availability. Further, the commenter states that the proposed emission rate may lead to hastily constructed tanks that may not be as soundly designed and constructed creating potential concerns for public health and safety as well as air quality.

The commenter contends that the EPA focused on the concept of any planned event that has the potential to increase emissions to or above 4 tpy. However, according to the commenter, this does not account for any potential short-term activities that may trigger reinstallation of controls such as degassing, refilling, inspection or maintenance when emissions in the long-term would otherwise remain below the 4 tpy level. The commenter states that this may result in the delay of appropriate maintenance or other actions that would otherwise be conducted. Building on the example of neighboring sites described above, the commenter states that, if the second site wanted to confirm tank integrity by inspection and cleaning, one-time emissions may raise the annual uncontrolled PTE to over 4 tpy, thus triggering not only reinstallation of controls but all associated monitoring, recordkeeping and reporting requirements.

Several commenters believe that a more appropriate approach would be to allow the removal of controls if a storage vessel has had uncontrolled actual emissions that remain below 6 tpy VOCs for 6 months. The commenters also believe that this initial determination is sufficient and that no further monitoring should be required unless otherwise required under § 60.5395(b)(2). According to the commenters, wells experiencing natural production decline are unlikely to ever experience an increase in emissions, but instead will continue to experience an emissions decrease. The commenters state that this continuing natural decline also supports the contention that 6 months is a sufficient timeframe to monitor emissions before removing controls.

One commenter adds that the proposed approach would require owners/operators to make a one-time commitment of what a tank will contain to the extent that potential emissions will ever exceed 6 tpy. The commenter believes that this inappropriately extends the "once in, always in" policy beyond its previous applications. While it appears that EPA would allow vessels to come in and out of regulation based on whether they contain crude oil, condensate, intermediate hydrocarbon liquids, or produced water at a given time, the commenter contended that the proposal would create a one-time determination of potential emissions that forever captures a tank, regardless of whether it continues to hold the materials that would bring it within regulation. In proposing low emitting storage vessels remain subject to the rule indefinitely, the commenter believes that the EPA is imposing unnecessary and burdensome control, recordkeeping, and reporting requirements on many storage vessels. Should EPA retain this "once in, always in" requirement, the commenter recommends that it should affirm that storage vessels no longer holding VOC-containing liquids or that are taken out of service are no longer an affected source.

Concerning re-installation of controls, several commenters state that the threshold should be 6 tpy instead of 4 tpy based on the EPA's cost effectiveness determination.

Response: To help alleviate the control supply shortage believed to exist at the time, we had proposed to amend the storage vessel emission standards to require compliance with either the 95 percent reduction requirement or an uncontrolled actual VOC emission rate of less than 4 tpy, which would allow control devices to be removed from storage vessel affected facilities below

that emission rate and relocated to those that have just come on line and have the VOC PTE of 6 tpy or more. As previously mentioned, new information we received since proposal indicates that the combustor suppliers have the manufacturing capacity to meet the demand posed by this NSPS, which in turn suggests that a supply buffer may no longer be necessary. However, for the reasons stated below, we have amended the storage vessel emission standards as proposed due to the cost effectiveness of continuing control and the increasing environmental disbenefits and energy impacts from the continued operation of the combustion control device at an inlet stream VOC concentration of less than 4 tpy.

As shown in the memo entitled *Cost and Secondary Environmental Impacts Associated with Controlling Storage Vessels under the Oil and Natural Gas Sector New Source Performance Standards,* available in the docket, our analysis indicates that the cost of controls for each storage vessel affected facility at a VOC emission rate of 4 tpy is approximately $5,100 per ton. This cost increases to approximately $6,900 per ton at an emission rate of 3 tpy, and to approximately $10,000 per ton at 2 tpy. For comparison, we note that, in a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost effective at a cost of $5,700/ton, which calls into question the cost effectiveness of continuing control of storage vessel affected facilities at an emission rate below 4 tpy.

One commenter recommends that, if we retain the uncontrolled VOC emission rate, it should be set no higher than 0.3 tpy (representing the emission rate of a 6 tpy VOC emission stream controlled at 95 percent) rather than 4 tpy. We emphasize that the 4 tpy uncontrolled VOC emission rate is not based on equivalency to the 95 percent reduction, nor do we think such conversion to an emission limit is appropriate considering it would result in a range of emission limits depending on the baseline uncontrolled emissions. The 0.3 tpy suggested by the commenter only represents the limit for sources with PTE of 6 tpy while those with higher PTE would have higher limits that equate to 95 percent reduction. Further, at the commenter's suggested emission rate of 0.3 tpy, the cost would be approximately $70,000 per ton of emission reduction, which we do not consider to be cost effective.

One commenter questioned the basis of our control cost estimates and pointed to a recent update by Colorado DPHE, an earlier version of which we used as the basis for our cost estimate, which indicated a lower cost of control. We point out that the lower cost in the revised Colorado analysis is primarily due to a lower cost (by approximately half) of the fuel for the pilot flame. Our assumption is that gas prices will remain relatively stable over time and question whether this lower fuel cost is applicable to all areas of the U.S. outside Colorado and whether such costs will be maintained in the long term. We also point out that the Colorado analysis did not include costs for a surveillance system or data management system, which were included in our analysis. Finally, the Colorado analysis showed an increase in capital cost of about $2,000 over the capital costs in our analysis. For these reasons, we believe our costs, if anything, may underestimate costs rather than overestimate as the commenter claims. We made no changes to our cost analysis based on this comment.

Another commenter suggested that our cost estimate overestimates costs because we did not take into account savings that would result when control devices are shared by storage vessels. The comment is incorrect. In our analysis, we assumed that there would be one control device used per well site. We also acknowledged that there are likely multiple storage vessels per well site, all of which would be routed to a single control device.

In addition to cost effectiveness, we evaluated the secondary impact from continuing control below 4 tpy. As shown in the memo entitled *Cost and Secondary Environmental Impacts Associated with Controlling Storage Vessels under the Oil and Natural Gas Sector New Source Performance Standards,* available in the docket, on a nationwide basis, the combustion of the pilot flame fuel and the combustion of the VOC vapor in the storage vessel vent stream will result in increases in NO_X, CO, CO_2, and methane emissions, most notably CO_2 emissions. We estimate that the operation of each combustion control device on a VOC storage vessel vent stream flow rate of 3 tpy will result in the following secondary emissions: 54 tpy of carbon dioxide (CO_2), 0.14 tpy of carbon monoxide (CO) and 0.028 tpy of nitrogen oxides (NO_X).

We also evaluated the energy impacts associated with continuing control below 4 tpy. The discussion here for secondary energy and environmental impacts is on the basis of one combustion control device. As of the date of publication of this preamble, we estimate that there are approximately 20,000 storage vessel affected facilities that require combustion control devices and that the number is projected to increase by about 11,000 per year. We also estimate that on average, from 2014 through 2020, approximately 8,000 storage vessel affected facilities per year will experience VOC emissions decline to below 4 tpy. Our information indicates that the fuel usage (primarily methane) for the pilot flame on a single combustion control device may be approximately 12 tpy (based on a fuel flow rate of 70 scf/hr for the pilot flame, or about 613 Mcf per year). Thus, at a storage vessel VOC emission rate of 4 tpy, a combustion device would have to combust an amount of fuel gas about 3 times the mass of the VOC vapor from the tank being controlled simply to keep the pilot flame operating. This ratio increases even further for VOC emission rates less than 4 tpy. Considering the nationwide energy impact of continuing to operate the pilot flame of an extremely large number of combustion control devices for VOC flow rates far lower than the pilot flame fuel flow rates, we question whether this is a responsible use of our energy resources.

In light of the cost-effectiveness, the secondary environmental impacts and the energy impacts, we have concluded that the BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained uncontrolled emission rates fall below 4 tpy. For the reason stated above, we have amended the storage vessel emission standards to require that, at all times, affected facilities comply with either the 95 percent reduction requirement or an uncontrolled actual VOC emission rate of less than 4, as proposed. Under the final amendments, an owner or operator may comply with the uncontrolled VOC emission rate instead of the 95 percent control requirement where it can be demonstrated that, based on records of monthly determinations of VOC emissions for the 12 consecutive months immediately preceding the demonstration, that the storage vessel affected facility uncontrolled actual VOC emissions each month during that 12-month period are below 4 tpy. The final amendments require that the owner or operator re-evaluate the uncontrolled VOC emissions on a monthly basis. For the same reasons discussed below in this section in our response to comments concerning storage vessels that are taken out of service, the 4 tpy alternative emission standards in the final amendments at § 60.5395(d)(2) require control to be

applied in either of two cases. First, if a well feeding a storage vessel affected facility undergoes fracturing or refracturing, the owner or operator must comply with the 95 percent reduction requirements in § 60.5395(d)(1) as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility, regardless of the last monthly emissions determination. On the other hand, if a monthly emissions determination required in § 60.5395(d)(2) indicates that VOC emissions from a storage vessel affected facility have increased to 4 tpy or greater, and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel, then the owner or operator must apply 95 percent control according to § 60.5395(d)(1) within 30 days of the monthly calculation.

One commenter stated that the 4 tpy uncontrolled VOC emission rate does not represent BSER. As previously explained, due to the cost effectiveness, the secondary environmental impact and energy impact, the 4 tpy emission rate likely represents a point below which continued control ceases to be the BSER for reducing VOC emissions from storage vessel affected facilities.

One commenter asserted that some maintenance events at neighboring sites may cause short-term spikes in VOC emissions of 4 tpy or more, thereby triggering control for at least another 12 months. As discussed above, the final amendments provide for two alternative emission standards, either of which must be met at all times. However, the 2012 NSPS contains affirmative defense provisions that may be considered in cases where malfunctions occur causing emissions to exceed the standard. Planned activities are expected to be conducted in compliance with the emission standards.

We also made changes to the final amendments to clarify our intent that the uncontrolled VOC emission rate is available for all storage vessel affected facilities. In the proposed amendments, § 60.5395(d)(2) conditionally allowed the owner or operator to meet an uncontrolled actual VOC emission rate so long as the monthly actual uncontrolled emission rate remained below 4 tpy. However, in the proposed amendments we included the following qualifier in § 60.5395(d)(2): "provided that you have been using a control device and have demonstrated that the VOC emissions have been below 4 tpy without considering control for at least the 12 consecutive months immediately preceding the demonstration."

We now believe that this qualifier places undue restriction on the use of the emission rate. Under the qualifier, Group 1 affected facilities that had uncontrolled emission below 4 tpy by the amended compliance date would not be able to avail itself of this option. We see no reason for such limitation and have therefore removed the qualifier language in the final amendments.

Concerning a commenter's assertion that one storage vessel with PTE of just over 6 tpy would be subject to control, recordkeeping and reporting requirements but that a storage vessel with PTE of just under 6 tpy would not be subject to any requirements, we respond that applicability thresholds exist for many rules and that subpart OOOO is not unique in that regard. With regard to the assertion that owners and operators may try to circumvent the NSPS by installing multiple small throughput storage vessels to keep individual tank emissions below the 6 tpy threshold, this comment pertains to the 2012 NSPS and not the proposed reconsideration, since changes to that threshold were not proposed. In response to the commenter's concern about transient emissions above 4 tpy that are caused by operator actions, storage vessels that increase emissions to at least the 4 tpy actual VOC emissions limit are subject to the control requirements. Owners and operators must ensure that they are aware of emissions increases that may occur after an activity and take appropriate action to control those emissions as required by the NSPS. With regard to uncontrolled VOC emissions of 6 tpy for 6 consecutive months being a more appropriate uncontrolled actual VOC emission limit, we have explained in section IV.B our rationale for the 4 tpy emission limit. In addition, we have never determined that control below 6 tpy is not cost-effective; to the contrary, we have determined that control at 4 tpy and above is cost-effective. Furthermore, we are concerned that setting the emission limit to allow removal of control if uncontrolled emissions are below 6 tpy for 6 consecutive months does not provide for reasonable certainty that emissions would not be controlled to the maximum extent possible that is still cost-effective and that does not create undue secondary impacts. Moreover, a full 12 months of sustained monthly uncontrolled actual emissions estimates below the 4 tpy limit will reasonably ensure that emissions fluctuations will not cause excursions above the limit, requiring controls to be reapplied. In the context of once in always in, the EPA has not extended this policy by providing that storage vessel affected facilities that subsequently reduce PTE to below 6 tpy remain affected facilities. The EPA historically has never let facilities in and out of affected facility status and is consistent in subpart OOOO. Having storage vessels remain affected facilities when emissions decline allows regulatory agencies to track emissions of these storage vessels and to monitor compliance if they increase. Further, operators are not restricted as to what they store in a tank; if the contents are crude oil, condensate, hydrocarbon intermediates or produced water, and the storage vessel has PTE of at least 6 tpy, it is a storage vessel affected facility and subject to subpart OOOO. In addition, in response to a comment that a tank is forever an affected facility regardless of its future contents, we disagree. If a tank ceases to be used for a purpose other than to hold an accumulation of any of the materials listed above, then it ceases to fit the definition of storage vessel under subpart OOOO and is therefore no longer an affected facility subject to the standards.

One commenter requests that we clarify that a storage vessel affected facility that is taken out of service ceases to be an affected facility under the NSPS. On the contrary, the storage vessel remains to be an affected facility, although we realize that there may be undue burden associated with control and monitoring, recordkeeping and reporting requirements for storage vessels that are not in service. However, if a storage vessel affected facility that is out of service is returned to service, an emissions determination is necessary to see whether it can continue compliance with the 4 tpy uncontrolled emission rate or it must now install control to meet the 95 percent reduction requirement. In the 2012 NSPS, we concluded that we need to provide sufficient time for determining emissions and, if necessary, installing control. See 77 FR 49490, at 49526 (August 16, 2012). Accordingly, the 2012 NSPS provide 30 days for determining emissions and an additional 30 days to make control operational. We believe that a similar time frame is needed for a dormant storage vessel returned to service to demonstrate continued compliance with the 4 tpy uncontrolled emission rate or to install control to meet the 95 percent reduction requirement. After all, these storage vessels may very well have very low emissions upon startup and should not be forced to install control immediately without an opportunity to demonstrate that they can continue

compliance with the 4 tpy uncontrolled emission rate. However, we are concerned that a dormant storage vessel that is returned to service associated with the fracturing or refracturing of a well feeding it is likely to release substantial amounts of vapor if not controlled right away due to the initially high liquid flow and flash emissions from freshly fractured or refractured wells. We also believe that potential emissions associated with fracturing and refracturing of a well are unlikely to meet the 4 tpy uncontrolled emission rate. We are therefore not providing the time period described above for storage vessels returned to service associated with fracturing or refracturing of a well. In light of these considerations, we have added language at § 60.5395(f) of the final amendments to address storage vessel affected facilities that are removed from service. After taking a storage vessel affected facility out of service, owners or operators are required provide notification in their next annual report that the storage vessel has been taken out of service. If a storage vessel's return to service is associated with fracturing or refracturing of a well feeding the storage vessel, the storage vessel must comply with control requirements in § 60.5395(d) immediately upon returning to service. If, however, the storage vessel's return to service is not associated with well fracturing or refracturing, the PTE of the storage vessel must be determined within 30 days. If the PTE is 4 tpy or greater, then the storage vessel affected facility must comply with control requirements in § 60.5395(d) within 60 days of being returned to service.

D. Major Comments Concerning Ongoing Compliance Requirements

1. Burden of Monitoring and Testing Requirements

Comment: One commenter states that the monitoring and testing requirements for storage vessels in the 2012 NSPS are overly complex and stringent given the large number of units affected and the remoteness of some wells sites. The commenter supports the EPA's intent to reduce the monitoring and testing burden on affected sources by means of the streamlined monitoring provisions in the proposed amendments. However, the commenter contends that many of these "streamlined" provisions remain overly burdensome due to the large number of affected vessels and the remoteness of the well sites at which they are installed. In particular, the commenter believes that § 60.5416 should only require an annual auditory, visual and olfactory (AVO) inspection of the vessel and control device, and that Method 22 observation should be required only if smoke is observed by the operator.

Another commenter states that, as proposed, the monthly inspections and obligations for prompt repairs can be accomplished with existing personnel and not add significantly to the cost of compliance while ensuring that the required emissions controls are operating properly.

Response: In this action, the EPA is finalizing the streamlined compliance monitoring requirements, as proposed, with minor clarifying changes. As we stated in the preamble to the proposed amendments (78 FR 22134), we will continue to fully evaluate the compliance demonstration and monitoring issues. We intend to complete our reconsideration of these requirements, along with other issues for which we intend to grant reconsideration, by the end of 2014.

In response to the comment stating that the streamlined monitoring provisions are still too burdensome, the EPA has re-evaluated the Method 22 requirements in the proposed reconsideration rule and continues to believe that an observation time of fifteen minutes with a one minute smoke allowance for all combustion controls is appropriate. For manufacturer-tested enclosed combustors, the required frequency of the Method 22 test is quarterly. For all other combustion controls, the required frequency of the Method 22 test is monthly. A "smoke/no smoke" determination is essentially what Method 22 requires. Method 22 simply requires the observer to note how long emissions were seen over a period of time (15 minutes for monthly testing, 1 hour for quarterly testing). If smoke is seen for more than a specified amount of time, it is a violation. We have information indicating that personnel are on-site at each well at least monthly. Since the Method 22 observation does not require highly trained personnel to conduct the test, we believe the personnel already on-site are capable of performing the test. Thus, we do not agree with the commenter that the monitoring provisions in the reconsideration proposal would result in undue burden, or that they are inappropriate considering the remoteness of the well sites. We have therefore finalized those provisions.

2. Streamlined Compliance Monitoring

Comment: Several commenters commented on the proposed streamlined compliance monitoring requirements for closed vent systems and control devices installed to reduce VOC emissions from storage vessels. Four commenters request that the EPA make the streamlined compliance monitoring requirements permanent. One of these commenters states that monitoring requirements imposed by the 2012 NSPS would be particularly onerous for small, independent operators that cannot afford the number of employees-hours required to travel to distant well sites with such high frequency. According to the commenters, their suggested changes to the proposed amendments would meet the goal of proper monitoring of emissions without requiring such a large amount of human and capital resources. Two commenters oppose the streamlined monitoring requirements and request that the EPA reinstate the more rigorous requirements in the 2012 NSPS. One commenter states that portions of the streamlined monitoring requirements are unnecessary and burdensome.

Another commenter expresses concern that the proposed amendments replace instrument-based monitoring of control devices and closed vent systems (CVS) with less reliable methods. Effective monitoring of the integrity and performance of emission control devices is vital to ensuring compliance with emissions limitations under section 111, according to the commenter, and is evident in the radically revised number of storage vessels with emissions exceeding 6 tpy.

The commenter pointed out that the current subpart OOOO requirements for continuous parametric monitoring system (CPMS) and Method 22 testing, as well as Method 21 monitoring, build on other long-standing EPA regulations, including storage vessel standards under subpart HH and the NSPS for volatile organic liquid storage vessels, subpart Kb. The commenter added that they are also consistent with the proposed Uniform Standards for CVS and storage vessels. According to the commenter, the EPA went in the wrong direction by proposing to eliminate the CPMS requirements, shorten the Method 22 visible emissions testing, and allow operators to inspect CVS using OVA inspections.

The commenter states that previous agency studies indicate that instrument-based monitoring is cost-effective and more sensitive than sensory inspections, suggesting that if anything subpart OOOO should extend such monitoring to all roof fittings that could emit VOC. The commenter contends that the EPA provided no information in the proposed reconsideration that questions

the findings of the Uniform Standards on relative effectiveness or cost of instrument monitoring of storage vessel components. The commenter also points to the Fort Berthold Indian Reservation Federal Implementation Plan (FBIR FIP) where the EPA required continuous parametric monitoring of enclosed combustors, utility flares, and other control devices. Also in the FBIR FIP according to the commenter, the EPA rejected reducing the Method 22 observation period to 1 hour to mitigate burdensome compliance costs as an option that was not suitable. The commenter does not believe the EPA provided specific information to warrant a different approach.

The commenter adds that the EPA did not demonstrate that the proposed changes are necessary to mitigate cost and burdens raised by industry. The commenter states that the EPA cited general personnel and infrastructure concerns in the preamble but did not provide an analysis of the anticipated costs of implementing monitoring. In proposing to determine that the current monitoring requirements were infeasible, the commenter contends that the EPA did not indicate whether it took into account the reduced monitoring costs associated with the Group 1 exemption for storage vessels that do not undergo an emissions-increasing event and the deferral of the Group 2 storage vessel compliance date.

Further, the commenter states that there is no indication as to whether Method 21 inspections, CPMS and full Method 22 testing would be infeasible at storage vessels at or near manned facilities. As a result, the commenter contends that the EPA's streamlined monitoring requirements appear to be overly broad as well as inadequately supported.

Another commenter adds that periodic monitoring of closed-vent systems and control devices is a very important part of controlling the air quality in the nation. The commenter asserts that most well sites are located far away from cities and sometimes it can be bothersome to drive back and forth in order to accomplish testing and monitoring processes. The commenter believes that the best way to encourage operators to use the appropriate models is by not letting them install equipment without proper documentation, and to fine them, or even stop onsite operations in case they do not obey the requirement.

Response: In today's action, the EPA is finalizing the streamlined compliance monitoring requirements, as proposed, with minor clarifying changes. In finalizing these provisions, the EPA has made no determination on the cost or feasibility of the compliance monitoring provisions in the 2012 NSPS, as some commenters appear to suggest. We also agree with the commenters about those provisions' reliability and effectiveness. However, as we explained in the preamble to the proposed amendments (78 FR 22134), significant issues regarding their implementation have been raised in the administrative petitions for reconsideration of the 2012 NSPS, which we are continuing to evaluate. We intend to complete our reconsideration of these requirements, along with any other issues for which we intend to grant reconsideration, by the end of 2014. We do not believe it is appropriate to impose these monitoring requirements on affected facilities while we are still evaluating their implementation issues. However, to avoid delaying compliance, we have proposed and are finalizing in today's action a set of streamlined compliance monitoring requirements. We believe that they are adequate to assure compliance. Several commenters urge us to retain the monitoring provisions in the 2012 NSPS for the reasons summarized above, but none of them claim that the streamlined provisions laid out in the proposal are inadequate to assure compliance. In light of the above, we are finalizing the streamlined compliance monitoring requirements, as proposed, with minor clarifying changes.

E. Major Comments Concerning Design Requirements

Comment: Three commenters support the inclusion of design parameters in the final amendments. One commenter states that design parameters are important to reduce the possibility for an unintended loophole in the rule language which might result in potentially significant emissions. The commenter adds that their agency has observed the highest emission rates corresponding to flash VOC emissions while liquids are being added to an existing storage vessel and believes that this is common at well sites, where the natural formation results in high pressure liquids which are then routed through the separator to a storage vessel that is at or around atmospheric pressure. The commenter contends that if a closed cover is not maintained during such liquids addition, a large percentage of the annual emissions could vent out of a pressure relief valve or thief hatch, rather than being routed to a control device.

Another commenter supported this view and states that the final amendments must ensure that vapor collection systems and control devices will reduce 95 percent of VOCs during all phases of operation, including when air pressure significantly increases during loading. The commenter contends that where systems are currently in place to control condensate tank emissions at natural gas exploration and production sites, they are sometimes inadequate for controlling the high-pressure vapor produced when the tanks receive a slug of condensate. The commenter points out that the EPA has noted in this rulemaking that the feasibility of meeting the storage-vessel standards with a vapor recovery unit may be affected by "fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel." The commenter provides several possible approaches to assure equipment is properly designed to meet the storage vessel standards.

One of the commenters adds that the inclusion of design requirements would provide enforceable provisions that would assist permitting agencies in regulating sources.

Eight commenters generally opposed the inclusion of design requirements in the final amendments. One commenter states that the EPA has already established BSER for affected storage vessels as the reduction of VOC emissions by 95 percent or greater and established work practice standards for the closed vent system to any control device or vapor recovery system. According to the commenter, these work practice standards address potential equipment design and maintenance issues that could affect the proper collection of and destruction or recovery of VOC emissions from storage vessels. The commenter asserts that a storage vessel, closed vent system, and control device that are not properly designed would not be able to meet the work practice standards and minimum control device destruction efficiency already required in the proposed rule; therefore, any process design standards would only be duplicative requirements and result in more burden to industry and state agencies responsible for compliance.

The commenter maintains that the EPA should not attempt to expand any NSPS regulations by specifically regulating the process or mechanical design of storage vessels or the closed vent system to control devices or vapor recovery systems. The commenter further states that owners and operators are responsible for designing process equipment based on individual site process conditions and safety considerations. According to the

commenter, it would be a massive undertaking for the EPA to attempt to write regulations regarding the specific "proper" design of storage vessels and closed vent systems. The commenter expresses doubt that the EPA could provide enough flexibility in process and mechanical design of equipment regulations to cover all the unique process conditions at individual facilities.

One commenter adds that over-prescriptive regulations on storage vessel design could stifle technological innovation, including new tank designs that emit less than current storage vessels. Additionally, according to the commenter, storage vessels are specifically designed in accordance with federal safety standards and these specifications should not be potentially compromised under any circumstances. Further, the commenter states that it is in the best economic interest of all operators to procure properly designed equipment and operate storage vessels efficiently. Lastly, the commenter states that, under the CAA, operators already have a general duty requirement to "maintain and operate any affected facility including air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions."

One commenter does not believe that the EPA has the authority under NSPS to require a particular technology or design as a performance standard. The commenter contends that the EPA should not mandate a particular technology, but rather allow companies to choose the technology to best meet the emission standard.

One state agency commenter believes that specifying design requirements in regulations will stifle innovation and create a plateau for new products. The commenter believes that such restrictions will not allow for economic or technological creation of new methods or equipment. The commenter further states that, as the industry grows and changes, so too should the facilities and equipment associated with it, but prescriptive design requirements would not allow this to happen. Also, according to the commenter, due to high variability of materials and situations in the field it seems illogical and inappropriate to deem only certain designs of facilities and equipment acceptable or not. The commenter contends that design requirements specified by rule could cause certain facilities or regions to be unable to implement engineering solutions necessary to account for site- or region-specific conditions.

Response: The EPA appreciates the information provided by these commenters in response to the EPA's solicitation of comment on whether the NSPS should include design requirements for storage vessels, closed vent system and control devices. In the preamble to the proposed rule, we had solicited comment on whether the EPA should require that storage vessel installations and associated controls be sized and designed properly for specific applications to minimize excess emissions due to improperly sized and designed storage vessels or control systems. We did not solicit comment on whether the EPA should require specific technology or design parameters. Accordingly, because the reconsideration proposal did not include any specific design requirements for storage vessels and associated closed vent systems and control device, no such requirement is included in the final amendments.

F. Major Comments Concerning Impacts

Comment: One commenter contends that the EPA failed to assess the air quality impacts of its proposed amendments and the EPA must provide further analysis of air quality impacts to support that the proposed revised standards is BSER. According to the commenter's analysis, Group 1 storage vessels that do not experience an event that would increase emissions would result in an increase from the final NSPS in VOC emissions of over 3 million tpy and methane emissions of over 700,000 tpy. In addition, the commenter states that the six-month delay of the compliance date for Group 2 storage vessels results in an increases of 450,000 tpy of VOC emissions and 100,000 tpy of methane emissions. The commenter added that the removal of a control device from sources whose uncontrolled emissions drop below 4 tpy would result in an emission increase of 3.8 tpy VOC per vessel. Assuming that the 11,600 new vessels the EPA projects would qualify for the uncontrolled actual VOC emission rate, emissions would increase by 23,000 tpy VOC and 5,000 tpy methane. The commenter also contends that the removal of the control device would result in sources left uncontrolled during any unplanned events that would generate significant emissions. Additionally, the commenter states that using their decline curve analysis, new sources would not qualify for uncontrolled actual VOC emission rate for at least 14 years, and the increase in pollution is not justified by the EPA's control device availability concerns.

Response: As we discussed in section IV.A of this preamble, we are not finalizing our proposal to subject only those Group 1 storage vessels that experience an event to the emission standards. Thus, all Group 1 storage vessel affected facilities will be subject to the emission standards, as required under the 2012 NSPS. We believe this addresses the commenters' concerns about any increase in emissions based on our proposal to require Group 1 to control only if there is a subsequent emission increase event. The commenter is also concerned with emission increase from delayed compliance. However, we believe that the extended deadlines in the final amendments are justified for the reasons stated in section IV.A, and we are phasing the compliance deadlines to address facilities with projected higher emissions more quickly.

We have also provided further analysis of air quality impacts, as the commenter suggests, as well as the cost effectiveness and energy impact associated with the proposed uncontrolled emission rate of less than 4 tpy. As discussed in more detail in section V.C of this preamble, 4 tpy likely represents a point below which control ceases to be the BSER for reducing VOC emissions from storage vessel affected facilities due to the cost effectiveness, the secondary environmental impact and energy impact.

VI. Technical Corrections and Clarifications

The EPA is finalizing corrections to recordkeeping and reporting requirements for all affected facilities. In addition, the final amendments include corrections that are editorial in nature, such as typographical and grammatical errors, as well as incorrect cross-references.

VII. Impacts of These Final Amendments

Our analysis shows that owners and operators of storage vessel affected facilities would choose to install and operate the same or similar air pollution control technologies under the proposed standards as would have been necessary to meet the previously finalized standards. We project that this rule will result in no significant change in costs, emission reductions, or benefits. Even if there were changes in costs for these units, 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. Since we believe that owners and operators would put on the same

controls for this revised final rule that they would have for the original final rule, there should not be any incremental costs related to this proposed revision.

A. What are the air impacts?

We believe that owners and operators of storage vessel affected facilities will install the same or similar control technologies to comply with the revised standards finalized in this action as they would have installed to comply with the previously finalized standards. Accordingly, we believe that this final rule will not result in significant changes in emissions of any of the regulated pollutants.

B. What are the energy impacts?

This final rule is not anticipated to have an effect on the supply, distribution, or use of energy. As previously stated, we believe that owners and operators of storage vessel affected facilities would install the same or similar control technologies as they would have installed to comply with the previously finalized standards.

C. What are the compliance costs?

We believe there will be no significant change in compliance costs as a result of this final rule because owners and operators of storage vessel affected facilities would install the same or similar control technologies as they would have installed to comply with the previously finalized standards. However, we note that there likely will be reductions of costs imposed on owners and operators associated with the streamlined compliance monitoring procedures provided in the final amendments.

D. What are the economic and employment impacts?

Because we expect that owners and operators of storage vessel affected facilities 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 standards, we do not anticipate that this final rule will result in significant changes in emissions, energy impacts, costs, benefits, or economic impacts. Likewise, we believe this rule will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy.

E. What are the benefits of the proposed standards?

As previously stated, the EPA anticipates the oil and natural gas sector will not incur significant compliance costs or savings as a result of this rule and we do not anticipate any significant emission changes resulting from this rule. Therefore, there are no direct monetized benefits or disbenefits associated with this rule.

VIII. Statutory and Executive Order Reviews

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

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

An RIA was prepared for the April 2012 NSPS and can be found at: *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf*. This final rule will not result in a significant change in costs, emission reductions, or benefits in 2015 (the year of full implementation of the 2012 NSPS being amended with this action).

B. Paperwork Reduction Act

This action does not impose any new information collection burden. This action does not change the information collection requirements previously finalized under the 2012 NSPS 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 49490) under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0673). The OMB control numbers for the EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

C. Regulatory Flexibility Act

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

For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the oil or natural gas industry 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.

After considering the economic impacts of today's final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The EPA has determined that none of the small entities will experience a significant impact because these final amendments will not impose additional compliance costs on owners or operators of affected facilities.

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 action imposes no enforceable duty on any state, local or tribal governments or the private sector. Therefore, this action is not subject to the requirements of sections 202 or 205 of the UMRA.

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 action contains no requirements that apply to small 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. This final rule is a reconsideration of an existing rule and imposes no new impacts or costs. 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 effect on tribal governments, on the relationship between the federal government and tribal governments or on the distribution of power and responsibilities between the federal government and tribal governments, 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 specifically solicited comment on the proposed action from tribal officials. The EPA notes that significant oil and natural gas development is occurring on some tribal lands and has been mindful of this in consideration of these final amendments.

G. Executive Order 13045: Protection of Children From Environmental Health 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, 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 final rule will not result in a significant change in emission reductions and benefits in 2015, the year of full implementation of the 2012 NSPS being amended with this action. Therefore, health and risk assessments were not conducted.

The public was invited to submit comments or identify peer-reviewed studies and data that assess effects of early life exposure to HAP from oil and natural gas sector activities.

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

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, 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. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable voluntary consensus standards.

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

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 human health or environmental protection for all affected populations. This final rule is a reconsideration of an existing rule and imposes no new impacts or costs. Therefore, this final rule would not have any disproportionately high and adverse human health or environmental effects on any population, including any minority, low income or indigenous 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 Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective September 23, 2013.

List of Subjects in 40 CFR Part 60

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping.

Dated: August 2, 2013.

Gina McCarthy,

Administrator.

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

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

Subpart OOOO—[Amended]

■ 2. Section 60.5365 is amended by revising paragraphs (e) and (h)(4) to read as follows:

§ 60.5365 Am I subject to this subpart?

* * * * *

(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, and has the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section by October 15, 2013 for Group 1 storage vessels and by April 15, 2014, or 30 days after startup (whichever is later) for Group 2 storage vessels. A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement

established under a Federal, State, local or tribal authority. Any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(1) through (4) of this section.

(1) You meet the cover requirements specified in § 60.5411(b).

(2) You meet the closed vent system requirements specified in § 60.5411(c).

(3) You maintain records that document compliance with paragraphs (e)(1) and (2) of this section.

(4) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(1) and (2) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

* * * * *

(b) * * *

(4) A gas well facility initially constructed after August 23, 2011, is considered an affected facility regardless of this provision.

■ 3. Section 60.5380 is amended by revising paragraphs (a)(2), (b), and (c) to read as follows:

§ 60.5380 What standards apply to centrifugal compressor affected facilities?

* * * * *

(a) * * *

(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), that is connected through a closed vent system that meets the requirements of § 60.5411(a) and routed to a control device that meets the conditions specified in § 60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

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

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

* * * * *

■ 4. Section 60.5390 is amended by:

■ a. Revising the introductory text;

■ b. Revising paragraph (a); and

■ c. Revising paragraph (c).

The revisions read as follows:

§ 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)(1) or (c)(1) 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)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller 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)(ii).

* * * * *

(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 or the point of custody transfer to an oil pipeline 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 or the point of custody transfer to an oil pipeline 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).

* * * * *

■ 5. Section 60.5395 is revised to read as follows:

§ 60.5395 What standards apply to storage vessel affected facilities?

Except as provided in paragraph (h) of this section, you must comply with the standards in this section for each storage vessel affected facility.

(a)(1) If you are the owner or operator of a Group 1 storage vessel affected facility, you must comply with paragraph (b) of this section.

(2) If you are the owner or operator of a Group 2 storage vessel affected facility, you must comply with paragraph (c) of this section.

(b) *Requirements for Group 1 storage vessel affected facilities.* If you are the owner or operator of a Group 1 storage vessel affected facility, you must comply with paragraphs (b)(1) and (2) of this section.

(1) You must submit a notification identifying each Group 1 storage vessel affected facility, including its location, with your initial annual report as specified in § 60.5420(b)(6)(iv).

(2) You must comply with paragraphs (d) through (g) of this section.

(c) *Requirements for Group 2 storage vessel affected facilities.* If you are the owner or operator of a Group 2 storage vessel affected facility, you must comply with paragraphs (d) through (g) of this section.

(d) You must comply with the control requirements of paragraph (d)(1) of this section unless you meet the conditions specified in paragraph (d)(2) of this section.

(1) Reduce VOC emissions by 95.0 percent according to the schedule specified in (d)(1)(i) and (ii) of this section.

(i) For each Group 2 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2014, or within 60 days after startup, whichever is later.

(ii) For each Group 1 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2015.

(2) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput for the month. Monthly calculations must be separated by at least 14 days. You must comply with paragraph (d)(1) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (d)(2)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (d)(1) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (d)(1) of this section within 30 days of the monthly calculation.

(e) *Control requirements.* (1) Except as required in paragraph (e)(2) of this section, if you use a control device to reduce emissions from your storage vessel affected facility, 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(c), and you must route emissions to a control device that meets the conditions specified in § 60.5412(c) and (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(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.

(f) *Requirements for storage vessel affected facilities that are removed from service.* If you are the owner or operator of a storage vessel affected facility that is removed from service, you must comply with paragraphs (f)(1) and (2) of this section.

(1) You must submit a notification in your next annual report, identifying all storage vessel affected facilities removed from service during the reporting period.

(2) If the storage vessel affected facility identified in paragraph (f)(1) of this section is returned to service, you must comply with paragraphs (f)(2)(i) through (iii) of this section.

(i) If returning your storage vessel affected facility to service is associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (d) of this section immediately upon returning the storage vessel to service.

(ii) If returning your storage vessel affected facility to service is not associated with a well that was fractured or refractured, you must comply with paragraphs (f)(2)(ii)(A) and (B) of this section.

(A) You must determine emissions as specified in § 60.5365(e) within 30 days of returning your storage vessel affected facility to service.

(B) If the uncontrolled VOC emissions without considering control from your storage vessel affected facility are 4 tpy or greater, you must comply with paragraph (d) of this section within 60 days of returning to service.

(iii) You must submit a notification in your next annual report identifying each storage vessel affected facility that has been returned to service.

(g) *Compliance, notification, recordkeeping, and reporting.* You must comply with paragraphs (g)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by § 60.5410(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by § 60.5415(e)(3).

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

(h) *Exemptions.* This subpart 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, 40 CFR part 63, subparts G, CC, HH, or WW.

■ 6. Section 60.5410 is amended by:
■ a. Revising the introductory text;
■ b. Revising paragraphs (a)(3) and (4);
■ c. Revising paragraphs (b)(2) through (5);
■ d. Revising paragraphs (b)(7) and (8);
■ e. Removing and reserving paragraph (c)(2);
■ f. Revising paragraphs (d) introductory text, (d)(1), (d)(2), and (d)(4);
■ g. Removing and reserving paragraph (e); and
■ h. Adding paragraphs (h) and (i).

The revisions and additions read as follows:

§ 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 (i) 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) * * *

(3) You must maintain a log of records as specified in § 60.5420(c)(1)(i) through (iv) 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), as an alternative to retaining the records specified in § 60.5420(c)(1)(i) through (iv), you may 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) * * *

(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) that is connected through a closed vent system that meets the requirements of § 60.5411(a) and is routed to a control device that meets the conditions specified in § 60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(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)(1) through (3).

(4) You must conduct the initial inspections required in § 60.5416(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417(a) through (g), as applicable.

* * * * *

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420(b)(3) for each centrifugal compressor affected facility.

(8) You must maintain the records as specified in § 60.5420(c)(2).

(c) * * *

(2) [Reserved]

* * * * *

(d) To achieve initial compliance with emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance 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 by a gas other than natural gas and therefore emits zero natural gas.

* * * * *

(4) You must tag each new pneumatic controller affected facility according to the requirements of § 60.5390(b)(2) or (c)(2).

* * * * *

(e) [Reserved]

* * * * *

(h) For each storage vessel affected facility, you must comply with paragraphs (h)(1) through (5) of this section. For a Group 1 storage vessel affected facility, you must demonstrate initial compliance by April 15, 2015, except as otherwise provided in paragraph (i) of this section. For a Group 2 storage vessel affected facility, you must demonstrate initial compliance by April 15, 2014, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in § 60.5365(e).

(2) You must reduce VOC emissions in accordance with § 60.5395(d).

(3) If you use a control device to reduce emissions, or if you route emissions to a process, you must demonstrate initial compliance by meeting the requirements in § 60.5395(e).

(4) You must submit the information required for your storage vessel affected facility as specified in § 60.5420(b).

(5) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420(c)(5) through (8) and § 60.5420(c)(12) and (13) for each storage vessel affected facility.

(i) For each Group 1 storage vessel affected facility, you must submit the notification specified in § 60.5395(b)(2) with the initial annual report specified in § 60.5420(b)(6).

■ 7. Section 60.5411 is amended by:

■ a. Revising the section heading;

■ b. Revising paragraphs (a) introductory text, (a)(1), and (a)(3)(i)(A);

■ c. Revising the heading of paragraph (b), and paragraphs (b)(1) and (b)(2)(iv);

■ d. Adding paragraph (b)(3); and

■ e. Adding paragraph (c).

The revisions and additions read as follows:

§ 60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels and centrifugal compressor wet seal degassing systems?

* * * * *

(a) Closed vent system requirements for centrifugal compressor wet seal degassing systems. (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the wet seal fluid degassing system to a control device or to a process that meets the requirements specified in § 60.5412(a) through (c).

* * * * *

(3) * * *

(i) * * *

(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 or process 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 or process to the atmosphere.

* * * * *

(b) *Cover requirements for storage vessels and centrifugal compressor wet seal degassing systems.* (1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief valves and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) * * *

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system designed and operated in accordance with the requirements of paragraph (a) or (c) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be weighted and properly seated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) *Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements specified in § 60.5412(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections. Each closed vent system that routes emissions to a process must be operational 95 percent of the year or greater.

(3) You must meet the requirements specified in paragraphs (c)(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 or to a process.

(i) Except as provided in paragraph (c)(3)(ii) of this section, you must comply with either paragraph (c)(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 or process to the atmosphere that sounds an alarm, or, initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process 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 (c)(3)(i) of this section.

■ 8. Section 60.5412 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(1) introductory text, and (a)(2);

■ b. Revising paragraph (b);

■ c. Revising paragraphs (c) introductory text and (c)(1); and

■ d. Adding paragraph (d).

The revisions and addition read as follows:

§ 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?

* * * * *

(a) Each control device used to meet the emission reduction standard in § 60.5380(a)(1) for your centrifugal compressor affected facility must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under § 60.5413(d), which meets the criteria in § 60.5413(d)(11) and § 60.5413(e).

(1) Each combustion device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

* * * * *

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated 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. As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of § 60.5413(c).

* * * * *

(b) You must operate each control device installed on your centrifugal compressor affected facility 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 wet seal fluid degassing system affected facility, as required under § 60.5380(a), 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(a) through (g), you must demonstrate compliance according to the requirements of § 60.5415(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(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) or according to the design required in paragraph (d)(2) of this section, 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)(10) and (12).

* * * * *

(d) Each control device used to meet the emission reduction standard in § 60.5395(d) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (3) of this section, as applicable. As an alternative, you may install a control device model tested under § 60.5413(d), which meets the criteria in § 60.5413(d)(11) and § 60.5413(e).

(1) Each enclosed combustion device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed to reduce the mass content of VOC emissions by 95.0 percent or greater. You must follow the requirements in paragraphs (d)(1)(i) through (iii) of this section.

(i) Ensure that each enclosed combustion device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of one minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's 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 inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A, visual observation as described in this paragraph.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) 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 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.

■ 9. Section 60.5413 is amended by:
■ a. Revising the introductory text;
■ b. Revising paragraph (a)(7);
■ c. Revising paragraph (d); and
■ d. Adding paragraph (e).

The revisions and addition read as follows:

§ 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 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 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. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer applicable to both storage vessel and centrifugal compressor affected facilities.

(a) * * *

(7) A control device whose model 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.

* * * * *

(d) *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 must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the

requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must 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 the minimum firing 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 the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported 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. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) through (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure inlet gas 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 gas flow monitoring meter.

(ii) Inlet flow rate must 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 gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) through (ii) of this section.

(i) 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 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 each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03.

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03.

(C) Higher heating value using ASTM D3588–98 or ASTM D4891–89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) through (B) of this section.

(A) The outlet sampling location must be 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) Flow rate must be measured using Method 1, 40 CFR part 60, appendix A–1 for determining flow measurement traverse point location, and Method 2, 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) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the Method 4, 40 CFR part 60, appendix A–3, moisture test following the procedure specified in (d)(7)(i)(A) through (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) 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. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, appendix A, must be modified 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) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4, 40 CFR part 60, appendix A–3. Traverse both ports with the Method 4, 40 CFR part 60, appendix A–3, sampling train during each test run. Ambient air must not be introduced into the Method 3C, 40 CFR part 60, appendix A–2, integrated bag sample during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, appendix A, equation 3B–1.

(8) Carbon monoxide must be determined using Method 10, 40 CFR part 60, appendix A. Run the test simultaneously with Method 25A, 40 CFR part 60, appendix A–7 using the same sampling points. An instrument range of 0–10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, appendix A–7, except that 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 each test run.

(ii) A valid test must consist of three Method 25A, 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 must 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 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, 40 CFR part 60, appendix A–2. You must use the following equation for this diluent concentration correction:

$$Ccorr = Cmeas\left(\frac{3}{CO_{2meas}}\right)$$

Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22, 40 CFR part 60, appendix A. 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, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Method 22, 40 CFR part 60, appendix A, results under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average Method 25A, 40 CFR part 60, appendix A, results under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess combustion air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(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)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A control device meeting the criteria in paragraph (d)(11)(i)(A) through (D) of this section must demonstrate a destruction efficiency of 95 percent for VOC regulated under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report required by this section in accordance with § 60.5420(b)(8).

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(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.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance requirements in (d)(11) of this section by installing a device tested under paragraph (d) of this section and complying with the criteria specified in paragraphs (e)(1) through (6) of this section.

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must 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, must be performed each calendar quarter. The observation period must be 1 hour and must be conducted according to EPA Method 22, 40 CFR part 60, appendix A.

(4) Devices failing the visible emissions test must follow manufacturer's 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 must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass an EPA Method 22, 40 CFR part 60, appendix A, visual observation as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section 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/*.

■ 10. Section 60.5415 is amended by:
■ a. Revising paragraphs (b) introductory text and (b)(2);
■ b. Revising paragraph (e) introductory text;
■ c. Removing and reserving paragraphs (e)(1) and (2);
■ d. Adding paragraph (e)(3); and
■ e. Revising paragraph (h)(1) introductory text.

The revisions and addition read as follows:

§ 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?

* * * * *

(b) For each centrifugal compressor affected facility, you must demonstrate continuous compliance according to paragraphs (b)(1) through (3) of this section.

* * * * *

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of § 60.5412(a) using the procedures specified in paragraphs (b)(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 must demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(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 (b)(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 (b)(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 criteria in § 60.5413(e) are met.

(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) and you demonstrate compliance using the test procedures specified in § 60.5413(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must 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 section 11. of Method 22, 40 CFR part 60, appendix A, must be performed each calendar quarter. The observation period must be 1 hour and must be conducted according to section 11. of EPA Method 22, 40 CFR part 60, appendix A.

(C) Devices failing the visible emissions test must follow manufacturer's 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 must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A, visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(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 (b)(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 (b)(2)(viii)(B) of this

section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(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 (b)(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 (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

* * * * *

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of § 60.5395(d)(1).

(1) [Reserved]

(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in § 60.5395(d).

(ii) For each control device installed to meet the requirements of § 60.5395(d), you must demonstrate continuous compliance with the performance requirements of § 60.5412(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with § 60.5416(c) for each cover and closed vent system.

(B) You must comply with § 60.5417(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in § 60.5411(c)(2).

* * * * *

(h) * * *

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in § 60.5415(h)(2), and must prove by a preponderance of evidence that:

* * * * *

■ 11. Section 60.5416 is amended by:
■ a. Revising the introductory text;
■ b. Revising paragraphs (a) introductory text, (a)(1)(ii), (a)(2)(iii), and (a)(3)(ii);
■ c. Revising paragraphs (b) introductory text, (b)(9) introductory text, and (b)(11); and
■ d. Adding paragraph (c).

The revisions and addition read as follows:

§ 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 applicable requirements of paragraphs (a) through (c) of this section.

(a) *Inspections for closed vent systems and covers installed on each centrifugal compressor affected facility.* Except as provided in paragraphs (b)(11) and (12) 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) * * *

(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; liquid leaks; 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) * * *

(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; liquid leaks; 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) * * *

(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 (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in § 60.5420(c)(7).

* * * * *

(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 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.

* * * * *

(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 (b)(10) of this section.

* * * * *

(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 (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) 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.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

* * * * *

(c) *Cover and closed vent system inspections for storage vessel affected facilities.* If you install a control device

or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (c)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c)(2) of this section, and inspect each bypass device according to the procedures of paragraph (c)(3) of this section. You must also comply with the requirements of (c)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(ii) Conduct olfactory, visual and auditory 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; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420(c)(7).

(ii) Conduct olfactory, visual and auditory 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.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in § 60.5411(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) Set the flow indicator to sound an alarm at the inlet to the bypass device when the stream is being diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to § 60.5420(c)(8).

(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 and records of each time the key is checked out, if applicable, according to § 60.5420(c)(8).

(4) *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 (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) 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 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *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.

(6) *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 (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) 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 (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *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 (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) 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.

■ 12. Section 60.5417 is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraph (b) introductory text;
■ c. Revising paragraph (c) introductory text;
■ d. Revising paragraphs (d)(1)(viii)(A) and (B);
■ e. Revising paragraph (d)(2);
■ f. Revising paragraph (f)(1)(iii);
■ g. Revising paragraph (g)(6)(ii); and
■ h. Adding paragraph (h).

The revisions and addition read as follows:

§ 60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?

* * * * *

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in § 60.5380, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) 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 (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

* * * * *

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

* * * * *

(d) * * *

(1) * * *

(viii) * * *

(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. The flow rate at the inlet to the combustion device must not exceed the maximum or minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of

the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. 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.

* * * * *

(f) * * *

(1) * * *

(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 your control device inlet gas flow rate must not exceed the maximum or minimum inlet gas flow rate determined by the manufacturer.

* * * * *

(g) * * *

(6) * * *

(ii) Failure of the quarterly visible emissions test conducted under § 60.5413(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in § 60.5395(d)(1) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(3) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with § 60.5413(d)(2) through (10), which meets the criteria in § 60.5413(d)(11), the reporting requirement in § 60.5413(d)(12), and meet the continuous compliance requirement in § 60.5413(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22, 40 CFR part 60, appendix A. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of pilot flame, or other indication of smoking or improper equipment operation (*e.g.*, visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in § 60.5420(c)(13).

■ 13. Section 60.5420 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising paragraph (a)(1);

■ c. Revising paragraph (b) introductory text;

■ d. Revising paragraph (b)(3)(iii);

■ e. Revising paragraph (b)(4)(i);

■ f. Revising paragraph (b)(5) introductory text;

■ g. Revising paragraph (b)(5)(i);

■ h. Revising paragraph (b)(6) introductory text;

■ i. Revising paragraphs (b)(6)(i) and (ii);

■ j. Adding paragraphs (b)(6)(iv) through (vii);

■ k. Revising paragraph (b)(7);

■ l. Adding paragraph (b)(8);

■ m. Revising paragraph (c) introductory text;

■ n. Revising paragraph (c)(1)(v);

■ o. Revising paragraph (c)(4)(ii);

■ p. Revising paragraph (c)(5);

■ q. Revising paragraphs (c)(6) through (11); and

■ r. Adding paragraphs (c)(12) and (13).

The revisions and additions read as follows:

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications 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, centrifugal compressor, reciprocating compressor or storage vessel affected facility you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4).

* * * * *

(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) or (8) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410. Subsequent annual reports are due no later than 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.

* * * * *

(3) * * *

(iii) If required to comply with § 60.5380(a)(1), the records specified in paragraphs (c)(6) through (11) of this section.

(4) * * *

(i) The cumulative number of hours of operation or the number of months since initial startup, since October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later.

* * * * *

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) 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(b)(2) or (c)(2).

* * * * *

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (vii) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to § 60.5365(e).

* * * * *

(iv) You must submit a notification identifying each Group 1 storage vessel affected facility in your initial annual report. You must include the location of the storage vessel, in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) A statement that you have met the requirements specified in § 60.5410(h)(2) and (3).

(vi) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395(f)(1).

(vii) You must identify each storage vessel affected facility for which operation resumes during the reporting period as specified in § 60.5395(f)(2)(iii).

(7)(i) Within 60 days after the date of completing each performance test (see § 60.8 of this part) as required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413(d), you must submit the results of the performance tests required by this subpart to the EPA as follows. You must use the latest version of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*) existing at the time of the performance test to generate a submission package file, which documents the performance test. You must then submit the file generated by the ERT through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed by logging in to the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). Only data collected using test methods supported by the ERT as listed on the ERT Web site are subject to this requirement for submitting reports electronically. 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. 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 § 60.4.

(ii) All reports, except as specified in paragraph (b)(8) of this section, 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 § 60.4 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).

(8) For enclosed combustors tested by the manufacturer in accordance with § 60.5413(d), an electronic copy of the performance test results required by § 60.5413(d) 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/*.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (13) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

(1) * * *

(v) For each gas well affected facility required to comply with both § 60.5375(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in § 60.5410(a)(4).

* * * * *

(4) * * *

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

* * * * *

(5) Except as specified in paragraph (c)(5)(v) of this section, 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(d)(1), the records specified in §§ 60.5420(c)(6) through (8), § 60.5416(c)(6)(ii), and § 60.6516(c)(7)(ii) of this subpart.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under § 60.5365(e) 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, as applicable.

(iv) For storage 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 storage vessel is removed from a site and, within 30 days, is either returned to or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage 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.

(v) You must maintain records of the identification and location of each storage vessel affected facility.

(6) Records of each closed vent system inspection required under § 60.5416(a)(1) for centrifugal compressors or § 60.5416(c)(1) for storage vessels.

(7) A record of each cover inspection required under § 60.5416(a)(3) for centrifugal compressors or § 60.5416(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of § 60.5416(a)(4) for centrifugal compressors or

§ 60.5416(c)(3) for storage vessels, 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) If you are subject to the closed vent system no detectable emissions requirements of § 60.5416(b) for centrifugal compressors, a record of the monitoring conducted in accordance with § 60.5416(b).

(10) For each centrifugal compressor affected facility, 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 centrifugal compressor subject to the control device requirements of § 60.5412(a), (b), and (c), 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.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5412(d)(2)) and records of each carbon replacement as specified in § 60.5412(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of § 60.5412(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in § 60.5417(h). You must maintain records of EPA Method 22, 40 CFR part 60, appendix A, section 11 results, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22–1 in EPA Method 22, 40 CFR part 60, appendix A. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

■ 14. Section 60.5430 is amended by:

■ a. Adding, in alphabetical order, definitions for the terms "Condensate," "Group 1 storage vessel," "Group 2 storage vessel," "Intermediate hydrocarbon liquid" and "Produced water;" and

■ b. Revising the definitions for "Flow line" and "Storage vessel" to read as follows:

§ 60.5430 What definitions apply to this subpart?

* * * * *

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

* * * * *

Flow line means a pipeline used to transport oil and/or gas to a processing facility, a mainline pipeline, re-injection, or routed to a process or other useful purpose.

* * * * *

Group 1 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after August 23, 2011, and on or before April 12, 2013.

Group 2 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after April 12, 2013.

* * * * *

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

* * * * *

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

* * * * *

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. For the purposes of this subpart, 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.

* * * * *

■ 15. Tables 1 and 2 to Subpart OOOO of part 60 are revised to read as follows:

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≤X≤5.0	5.0<X≤15.0	15.0<X≤300.0	X>300.0
Y≥50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
20≤Y<50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9
10≤Y<20	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 93.5, 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≤X≤5.0	5.0<X≤15.0	15.0<X≤300.0	X>300.0
Y≥50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
20≤Y<50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller		97.5
10≤Y<20	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
Y<10	74.0	74.0	74.0	74.0

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.

[FR Doc. 2013–22010 Filed 9–20–13; 8:45 am]

BILLING CODE 6560–60–P